BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

In the Matter of the Application of PACIFICORP for an Order Authorizing a Change in Depreciation Rates Applicable to Electric Property.	))))	Case No. __________ Direct Testimony of Kathryn C. Hymas

PACIFICORP

October, 2002

Q. Please state your name, business address and position with PacifiCorp (the Company).

A. My name is Kathryn C. Hymas. My business address is 825 N.E. Multnomah Street, Suite 2000, Portland, Oregon, 97232. I am employed by the Company as Managing Director and Corporate Business Services Controller.

Q. Please briefly describe your professional experience and educational background.

A. I have worked for PacifiCorp for the last 19 years in a variety of accounting and finance positions. I have a Bachelor of Science in Accounting and a Masters in Accountancy, both from Brigham Young University. I am a Certified Public Accountant. Prior to my employment at PacifiCorp, I worked for four years in public accounting for Grant Thornton in Chicago, Illinois.

Q. What is the purpose of your testimony?

A. I will summarize the Company's proposal for depreciation rates. I will also summarize the effect on annual depreciation expense from applying the proposed depreciation rates to depreciable plant balances. The rates are contained in the 2002 depreciation study performed on behalf of the Company by Mr. Donald S. Roff of Deloitte & Touche LLP. The depreciation study performed by Mr. Roff is provided as Exhibit No.4 and will be referred to hereafter as the D&T study.

Second, I will introduce the other Company witnesses who will testify in this proceeding.

Third, I will provide background information describing the depreciation study process. This information will present the Company's confidence in both the depreciation study process and in the integrity of the Company's accounting data relied on by Mr. Roff in preparing the depreciation study.

Fourth, I will discuss a number of significant issues considered during the preparation of this study. The disposition of these issues was reflected in the data provided to Mr. Roff and, in turn, this data formed the basis for the D&T study and the recommended changes in depreciation rates.

Finally, I will indicate the Company's proposed effective date for implementing the changes in depreciation rates.

PLANT LIVES, DEPRECIATION RATES AND DEPRECIATION EXPENSE

Q. What depreciation rates is the Company seeking Commission approval for in this proceeding?

A. The Company seeks Commission approval to adopt the depreciation rates contained in the depreciation study performed by Mr. Donald S. Roff and as recommended in Mr. Roff's testimony. As shown in Table A of Exhibit No. 4 and as summarized in Mr. Roff's testimony, the D&T study proposes no change to the composite depreciation rate of 3.11 percent for the Company's electric utility plant. This composite rate is based on the March 31, 2002 depreciable plant balances used in the study. The specific depreciation rate changes recommended for the components of the composite depreciation rate are set forth in account detail in Schedule 1 of the D&T study.

Q. What is the effect on annual depreciation expense from adopting the depreciation rates recommended by Mr. Roff?

A. The effect of applying the recommended depreciation rates to the March 31, 2002 depreciable plant balances is a decrease in total Company annual depreciation expense of approximately $0.7 million, compared with the level of annual depreciation expense developed by application of the currently authorized depreciation rates to the same plant balances. Annual depreciation expense by functional plant classification is summarized in Table A of the D&T study.

Adoption of the depreciation rates proposed in the D&T study results in an increase of approximately $0.6 million in annual Idaho jurisdiction depreciation expense, based on March 31, 2002 depreciable plant balances. The calculation of the Idaho jurisdiction amount is described in Exhibit No. 1.

<u>INTRODUCTION OF WITNESSES</u>

Q. In addition to yourself, who will be testifying on behalf of PacifiCorp in this proceeding?

A. In addition to myself, two witnesses will testify on behalf of the Company. These witnesses are Mr. Donald S. Roff, Director of the Public Utilities Group at Deloitte & Touche LLP and Mr. Barry G. Cunningham, Senior Vice-President of Generation for PacifiCorp.

Mr. Roff will present the depreciation rates for which the Company is seeking Commission approval. He describes how the depreciation study was prepared and discusses the primary reasons for the recommended changes in depreciation rates. The first reason Mr. Roff discusses is the effect on depreciation rates of using the estimated generation plant life spans described in Mr. Cunningham's testimony. He also discusses the effect on depreciation rates from the recognition of less negative net salvage for distribution plant assets, the decrease for which is reflective of the Company's current removal and salvage experience. Mr. Roff also discusses the effect on depreciation rates of additional investment in plant, installed since the 1998 depreciation study. That study will be referred to hereafter as the 1998 study.

Mr. Cunningham will explain the process used by the Company's generation engineering staffs to develop estimated life spans for the Company's thermal and hydroelectric generating plants. He will also explain why the Company proposes to continue using the steam plant life spans reflected in current depreciation rates. In addition, Mr. Cunningham will explain the reasons for including terminal net salvage in the steam generating plant depreciation rates, and will explain the inclusion of decommissioning and removal costs for the Company's Condit and American Fork Hydroelectric plants. Finally, Mr. Cunningham will discuss the depreciation of water rights acquired for the operation of steam generating plants and explain why such depreciation is appropriate for ratemaking purposes.

DEPRECIATION STUDY BACKGROUND

Q. Was the D&T study prepared under your direction?

A. Yes. As Controller for Corporate Business Services, I have responsibility for the Company's accounting departments and for implementing Company accounting policies and procedures. This includes periodic review and study of depreciation rates.

Q. Why was it necessary for the Company to conduct the D&T study?

A. It is sound accounting practice to periodically update depreciation rates to recognize additions to investment in plant assets and to reflect changes in asset characteristics, technology, salvage, removal costs, life span estimates and other factors that impact depreciation rate calculations. Current depreciation rates were developed from the 1998 study that was based on depreciable plant balances at December 31, 1997. The Company typically conducts depreciation studies approximately at five-year intervals.

Q. What conclusions has the Company reached in this proceeding?

A. The Company concludes that the D&T study has been prepared in a professional manner, that it is well supported by the underlying engineering and accounting data and that it results in depreciation rates that are fair and reasonable.

Q. Please explain the concept of depreciation.

A. There are many definitions of depreciation. The following definition was put forth by the American Institute of Certified Public Accountants in its <u>Accounting Research and Terminology Bulletin #1</u>:

> Depreciation accounting is a system of accounting which aims to distribute the cost or other basic value of tangible capital assets, less salvage (if any), over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner.

The actual payment for electric utility plant assets occurs in the period in which it is acquired through purchase or construction. Depreciation accounting spreads this cost over the useful life of the property. The fundamental reason for recording depreciation is to provide for accurate measurement of a utility's results of operations. Capital investments in the buildings, plant, and equipment necessary to provide electric service are essentially a prepaid expense, and annual depreciation is the part of that expense applicable to each successive accounting period over the service life of the property. Annual depreciation is an important and essential factor in informing investors and others of a company's periodic income. If it is omitted or distorted, a company's periodic income statement is distorted.

Q. Why is depreciation especially important to an electric utility?

A. An electric utility is very capital intensive; that is, it requires a tremendous investment in generation, transmission and distribution equipment with long lives to bring electricity to customers. Thus, the annual depreciation of this equipment is a major item of expense to the utility. Regulated electric prices are expected to allow the utility to fully recover its operating costs and earn a fair return on its investment. If depreciation rates are established at an inadequate level for ratemaking purposes, the utility will not recover its operating costs and will earn less than a fair return on its investment.

Q. Do you believe that the plant lives and depreciation rates developed in the D&T study provide the Company with a fair and equitable recovery of its investment in electric utility plant and equipment?

A. Yes, I believe the depreciation rates developed in the D&T study produce an annual depreciation expense, which is fair and reasonable for both financial reporting and ratemaking purposes.

Q. What is the basis for your confidence in the D&T study?

A. I believe that a good depreciation study is the product of sound analytical procedures applied to accurate, reliable accounting and engineering data. I have full confidence in Mr. Roff's choice and application of analytical procedures as described in his testimony. With respect to data inputs, the steam generating plant lives used in the study, with the exception of Naughton, are those reflected in current depreciation rates. Retirement dates for hydro and other production plant are based on the latest engineering estimates. Life estimates for other types of plant and equipment are based on Mr. Roff's actuarial analysis of the data and reviewed for reasonableness by those familiar with their operation. The accounting data has also been consistently prepared. Company employees trained in depreciation techniques extracted and summarized the retirement, salvage, and removal cost data from the accounting system, and then reviewed it for completeness and accuracy before it was provided to Mr. Roff for use in this study. Because I am comfortable with both the quality of the data inputs and the professionalism of the analysis, I have complete confidence in the recommendations contained in the D&T depreciation study.

SIGNIFICANT ISSUES

Q. Please summarize the significant issues you've considered in the current study.

A. One significant issue is the Company's proposal not to change steam generating plant life spans. The D&T study reflects the same lives for steam plants that were used in the 1998 study to develop current depreciation rates, modified only to extend the life span for the Naughton Plant from 44 to 54 years as discussed by Mr. Cunningham.

Q. What is the other significant issue you considered in this study?

A. The other major factor impacting the current study is the reduction in negative net salvage for distribution plant assets.

Q. Please describe negative net salvage for distribution plant and explain why it is considered a significant item in this study.

A. Let me begin by first defining the terms net salvage and negative net salvage. Net salvage refers to the salvage value of property retired less the cost of removal. Negative net salvage occurs when the cost of removal exceeds the salvage value for property retired. Annual net salvage is expressed as a percentage in the depreciation study and is calculated by dividing the net salvage amount by the retirement amounts. Mr. Roff in his testimony discusses the propriety of reflecting negative net salvage in depreciation rates and the impact on depreciation rates of recognizing negative net salvage.

Q. What is the reason less negative net salvage is being incurred by the Company for distribution plant assets?

A. Various accounting changes have been adopted which have combined to cause a decrease in the recognition of distribution removal costs. In 1999, the Company changed the accounting for various items such as cross-arms, down-guys, anchors, and insulators from recording them as individual retirement units to the concept of the "fully dressed pole", which treats these items as components of a retirement unit. As a result, removal and replacement of these items, independent of the retirement unit, became an expense transaction instead of removal.

Also in 1999, the manual recording of removal costs for both transformers and meters was eliminated as part of process re-engineering to eliminate manual processes. To replace the manual entries for the removal of transformers, the process was automated in the estimating system. The spare line transformers were reclassified from Electric Plant to materials and supplies. This resulted in the accounting for transformers, including removal costs, being estimated and charged along with the other distribution line assets in the work order system. For meters, the manual process of recording removal costs was not replaced at that time; however, a process for recording meter removal costs is being developed, which will result in increased meter removal costs in future analysis.

Q. What procedures does the Company use to ensure salvage and cost of removal for distribution plant is properly recorded in the accounting records?

A. The Company uses a work order system to record capital activity including additions, retirements, removal costs and salvage. A work order is established when operating departments identify property retirement units (PRUs) being installed, removed or replaced. Actual project labor and/or contractor costs incurred to remove PRUs are directly charged to the work order and are closed to the general ledger.

Distribution projects are estimated by Company engineers using the Regional Construction Management System (RCMS). RCMS uses engineered work standards ("construction standards") for each PRU to estimate the amount and percentage for allocating labor charges between installation and removal activities. Actual labor costs charged to the work order are allocated to the removal account and to the construction accounts based on these construction standards. Proceeds received from salvage of removed materials are credited back to the work order.

The use of work orders, the RCMS system and construction standards combine to provide a reliable and consistent process for recording salvage and cost of removal.

EFFECTIVE DATE

Q. What does PacifiCorp propose as the effective date for implementing the D&T study depreciation rates?

A. The Company proposes that the new depreciation rates be made effective April 1, 2002.

RECOMMENDATIONS

Q. Summarize your recommendations to the Commission?

A. I recommend that the Commission find the recommendations made by Mr. Roff in the D&T study regarding depreciation rates to be the proper and current depreciation rates for the Company and that the Commission order the Company to reflect the depreciation rates proposed in the D&T study in its accounts and records effective April 1, 2002.

Q. Does this conclude your testimony?

A. Yes.

Case No. _________
Exhibit No. 1
Witness: Kathryn C. Hymas

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

PACIFICORP

Exhibit Accompanying Direct Testimony of Kathryn C. Hymas

IDAHO Depreciation Rate Comparison - FYMar02

October, 2002

Exhibit No. 1, Pg. 1 of 4
Case No. ______
Witness: Kathryn C. Hymas

PACIFICORP
IDAHO Depreciation Rate Comparison - FYMar02

PLANT	ACCT	AF	PLANT-IN-SERVICE TOTAL	PLANT-IN-SERVICE NONDEP	PLANT-IN-SERVICE NET	DEP RATE EXISTING	DEP RATE PROPOSED	TOTAL COMPANY DEPRECIATION EXISTING	TOTAL COMPANY DEPRECIATION PROPOSED	TOTAL COMPANY DEPRECIATION DIFFERENCE	IDAHO ALLOCATION FACTOR	IDAHO ALLOCATION AMOUNT
Steam Production Plant		DGP	1,282,396,016.80	(2,635,923.53)	1,279,760,093.27	2.85%	3.31%	36,475,639.18	42,372,454.52	5,896,815.33	0.00%	-
Steam Production Plant		DGU	1,441,149,590.75	(7,456,889.87)	1,433,692,700.88	3.02%	3.33%	43,287,827.94	47,736,746.76	4,448,918.81	13.44%	597,989.44
Steam Production Plant		SG	1,456,678,760.32	(32,708,156.27)	1,423,970,604.05	2.91%	3.38%	41,368,994.12	48,088,826.05	6,719,831.93	6.49%	435,933.09
TOTAL STEAM			4,180,224,367.87	(42,800,969.67)	4,137,423,398.20	2.93%	3.34%	121,132,461.24	138,198,027.32	17,065,566.08		1,033,922.53
Hydraulic Production Plant		DGP	248,981,329.08	(3,391,763.38)	245,589,565.70	2.44%	2.75%	5,992,377.93	6,746,257.85	753,879.92	0.00%	-
Hydraulic Production Plant		DGU	49,396,985.22	(4,456,877.47)	44,940,107.75	2.39%	2.76%	1,074,750.13	1,241,289.62	166,539.49	13.44%	22,384.96
Hydraulic Production Plant		SG	180,530,798.49	(4,399,381.02)	176,131,417.47	3.74%	4.16%	6,590,770.02	7,320,991.33	730,221.31	6.49%	47,371.37
TOTAL HYDRO			478,909,112.79	(12,248,021.87)	466,661,090.92	2.93%	3.28%	13,657,898.09	15,308,538.81	1,650,640.72		69,756.32
Other Production Plant		DGP	-	-	-	0.00%	0.00%	-	-	-	0.00%	-
Other Production Plant		DGU	3,059,951.14	(635.22)	3,059,315.92	4.12%	3.51%	125,926.91	107,256.69	(18,670.23)	13.44%	(2,509.51)
Other Production Plant		SG	199,454,480.95	(842,244.88)	198,612,236.07	2.86%	3.24%	5,686,888.01	6,438,799.11	751,911.10	6.49%	48,778.44
TOTAL OTHER			202,514,432.09	(842,880.10)	201,671,551.99	2.88%	3.25%	5,812,814.92	6,546,055.80	733,240.87		46,268.93
Transmission Plant		DGP	613,400,753.47	(2,470,691.11)	610,930,062.36	1.98%	2.17%	12,120,733.86	13,273,630.68	1,152,896.82	0.00%	-
Transmission Plant		DGU	680,459,971.05	(27,350,581.95)	653,109,389.10	2.01%	2.17%	13,153,296.08	14,165,650.52	1,012,354.44	13.44%	136,072.90
Transmission Plant		SG	955,639,636.14	(2,552,950.33)	953,086,685.81	2.08%	2.19%	19,838,475.15	20,863,641.41	1,025,166.27	6.49%	66,505.22
TOTAL TRANSMISSION			2,249,500,360.66	(32,374,223.39)	2,217,126,137.27	2.03%	2.18%	45,112,505.08	48,302,922.61	3,190,417.53		202,578.12
Distribution Plant		CA	164,832,602.56	(116,221.85)	164,716,380.71	4.11%	2.63%	6,774,254.44	4,334,053.34	(2,440,201.11)	0.00%	-
Distribution Plant		IDU	185,717,671.53	(189,958.87)	185,527,712.66	3.55%	2.99%	6,589,963.78	5,547,991.46	(1,041,972.31)	100.00%	(1,041,972.31)
Distribution Plant		OR	1,279,163,133.88	(3,452,055.29)	1,275,711,078.59	4.16%	3.17%	53,058,175.77	40,382,074.25	(12,676,101.51)	0.00%	-
Distribution Plant		UT	1,460,568,149.39	(6,262,718.17)	1,454,305,431.22	3.31%	2.84%	48,165,207.59	41,295,102.50	(6,870,105.08)	0.00%	-
Distribution Plant		WA	294,081,503.33	(659,888.80)	293,421,614.53	3.81%	3.06%	11,193,829.28	8,972,161.48	(2,221,667.80)	0.00%	-
Distribution Plant		WYP	328,304,186.51	(477,336.93)	327,826,849.58	3.46%	3.05%	11,342,673.44	10,005,580.09	(1,337,093.36)	0.00%	-
Distribution Plant		WYU	60,438,166.01	(48,779.75)	60,389,386.26	3.54%	3.25%	2,135,765.63	1,964,937.36	(170,828.27)	0.00%	-
TOTAL DISTRIBUTION			3,773,105,413.21	(11,206,959.66)	3,761,898,453.55	3.70%	2.99%	139,259,869.93	112,501,900.49	(26,757,969.45)		(1,041,972.31)
General Plant - Depreciable	389	CA	217,568.45	(217,568.45)	-	2.51%	2.36%	-	-	-	0.00%	-
General Plant - Depreciable	389	CN	1,109,264.15	(1,109,264.15)	-	2.51%	2.36%	-	-	-	3.78%	-
General Plant - Depreciable	389	DGU	16,174.13	(12,946.30)	3,227.83	2.51%	2.36%	81.02	76.18	(4.84)	13.44%	(0.65)
General Plant - Depreciable	389	SG	1,227.55	-	1,227.55	2.51%	2.36%	30.81	28.97	(1.84)	6.49%	(0.12)
General Plant - Depreciable	389	IDU	382,543.07	(380,220.81)	2,322.26	2.51%	2.36%	58.29	54.81	(3.48)	100.00%	(3.48)
General Plant - Depreciable	389	OR	1,298,320.96	(1,298,320.96)	-	2.51%	2.36%	-	-	-	0.00%	-
General Plant - Depreciable	389	SO	5,830,111.92	(5,830,111.92)	-	2.51%	2.36%	-	-	-	6.12%	-
General Plant - Depreciable	389	UT	3,007,112.85	(2,973,724.80)	33,388.05	2.51%	2.36%	838.04	787.96	(50.08)	0.00%	-
General Plant - Depreciable	389	WA	1,254,137.46	(1,254,137.46)	-	2.51%	2.36%	-	-	-	0.00%	-
General Plant - Depreciable	389	WYP	139,755.65	(139,728.57)	27.08	0.00%	0.00%	-	-	-	0.00%	-
General Plant - Depreciable	389	WYU	825,613.55	(825,613.55)	-	2.51%	2.36%	-	-	-	0.00%	-
General Plant - Depreciable	390	CA	2,016,090.81	(605,832.87)	1,410,257.94	1.93%	2.22%	27,217.98	31,307.73	4,089.75	0.00%	-
General Plant - Depreciable	390	CN	9,878,185.32	(2,335,156.37)	7,543,028.95	2.38%	2.43%	179,524.09	183,295.60	3,771.51	3.78%	142.55
General Plant - Depreciable	390	CN	9,180.36	-	9,180.36	2.55%	2.74%	234.10	251.54	17.44	3.78%	0.66
General Plant - Depreciable	390	DGP	26,472.29	-	26,472.29	2.55%	2.74%	675.04	725.34	50.30	0.00%	-
General Plant - Depreciable	390	DGP	46,441.61	-	46,441.61	3.12%	3.80%	1,448.98	1,764.78	315.80	0.00%	-
General Plant - Depreciable	390	DGP	129,705.98	-	129,705.98	3.19%	2.58%	4,137.62	3,346.41	(791.21)	0.00%	-
General Plant - Depreciable	390	DGP	182,702.78	-	182,702.78	3.32%	2.33%	6,065.73	4,256.97	(1,808.76)	0.00%	-
General Plant - Depreciable	390	DGU	1,525,772.82	-	1,525,772.82	2.38%	2.43%	36,313.39	37,076.28	762.89	13.44%	102.54
General Plant - Depreciable	390	DGU	151,835.77	-	151,835.77	3.19%	2.58%	4,843.56	3,917.36	(926.20)	13.44%	(124.49)
General Plant - Depreciable	390	IDU	9,083,487.09	-	9,083,487.09	2.38%	2.43%	216,186.99	220,728.74	4,541.74	100.00%	4,541.74
General Plant - Depreciable	390	OR	24,083,033.84	(9,667,672.11)	14,415,361.73	2.55%	2.74%	367,591.72	394,980.91	27,389.19	0.00%	-
General Plant - Depreciable	390	SG	2,748.74	-	2,748.74	1.93%	2.22%	53.05	61.02	7.97	6.49%	0.52
General Plant - Depreciable	390	SG	1,255,510.36	-	1,255,510.36	2.38%	2.43%	29,881.15	30,508.90	627.76	6.49%	40.72
General Plant - Depreciable	390	SG	1,354,493.83	-	1,354,493.83	2.55%	2.74%	34,539.59	37,113.13	2,573.54	6.49%	166.95

PACIFICORP
IDAHO Depreciation Rate Comparison - FYMar02

PLANT	ACCT	AF	PLANT-IN-SERVICE TOTAL	PLANT-IN-SERVICE NONDEP	PLANT-IN-SERVICE NET	DEP RATE EXISTING	DEP RATE PROPOSED	TOTAL COMPANY DEPRECIATION EXISTING	TOTAL COMPANY DEPRECIATION PROPOSED	TOTAL COMPANY DEPRECIATION DIFFERENCE	IDAHO ALLOCATION FACTOR	IDAHO ALLOCATION AMOUNT
General Plant - Depreciable	390	SG	18,204.39	-	18,204.39	3.12%	3.80%	567.98	691.77	123.79	6.49%	8.03
General Plant - Depreciable	390	SG	68,814.93	-	68,814.93	3.19%	2.58%	2,195.20	1,775.43	(419.77)	6.49%	(27.23)
General Plant - Depreciable	390	SG	157,010.79	-	157,010.79	3.32%	2.33%	5,212.76	3,658.35	(1,554.41)	6.49%	(100.84)
General Plant - Depreciable	390	SO	45,047,281.79	(10,621,334.41)	34,425,947.38	2.38%	2.43%	819,337.55	836,550.52	17,212.97	6.12%	1,053.53
General Plant - Depreciable	390	SO	38,861,504.58	-	38,861,504.58	2.55%	2.74%	990,968.37	1,064,805.23	73,836.86	6.12%	4,519.22
General Plant - Depreciable	390	UT	30,691,472.62	-	30,691,472.62	2.38%	2.43%	730,457.05	745,802.78	15,345.74	0.00%	-
General Plant - Depreciable	390	WA	11,301,600.32	(1,999,061.69)	9,302,538.63	3.12%	3.80%	290,239.21	353,496.47	63,257.26	0.00%	-
General Plant - Depreciable	390	WYP	8,125,937.54	(6,495,698.59)	1,630,238.95	3.19%	2.58%	52,004.62	42,060.16	(9,944.46)	0.00%	-
General Plant - Depreciable	390	WYU	3,067,565.19	-	3,067,565.19	3.19%	2.58%	97,855.33	79,143.18	(18,712.15)	0.00%	-
General Plant - Depreciable	391	SO	5,191,952.96	-	5,191,952.96	2.42%	26.85%	125,645.26	1,394,039.37	1,268,394.11	6.12%	77,632.69
General Plant - Depreciable	397	CA	2,593,599.27	-	2,593,599.27	3.89%	4.15%	100,891.01	107,634.37	6,743.36	0.00%	-
General Plant - Depreciable	397	CN	2,016,271.87	-	2,016,271.87	5.03%	4.75%	101,418.48	95,772.91	(5,645.56)	3.78%	(213.39)
General Plant - Depreciable	397	CN	3,118,952.65	-	3,118,952.65	5.58%	6.28%	174,037.56	195,870.23	21,832.67	3.78%	825.22
General Plant - Depreciable	397	DGP	1,133,951.77	-	1,133,951.77	3.75%	5.30%	42,523.19	60,099.44	17,576.25	0.00%	-
General Plant - Depreciable	397	DGP	244,253.82	-	244,253.82	3.89%	4.15%	9,501.47	10,136.53	635.06	0.00%	-
General Plant - Depreciable	397	DGP	1,078,073.22	-	1,078,073.22	4.97%	3.93%	53,580.24	42,368.28	(11,211.96)	0.00%	-
General Plant - Depreciable	397	DGP	40,545.44	-	40,545.44	5.03%	4.75%	2,039.44	1,925.91	(113.53)	0.00%	-
General Plant - Depreciable	397	DGP	1,349,339.96	-	1,349,339.96	5.34%	4.86%	72,054.75	65,577.92	(6,476.83)	0.00%	-
General Plant - Depreciable	397	DGP	2,984,178.30	-	2,984,178.30	5.58%	6.28%	166,517.15	187,406.40	20,889.25	0.00%	-
General Plant - Depreciable	397	DGU	9,572,676.08	-	9,572,676.08	5.03%	4.75%	481,505.61	454,702.11	(26,803.49)	13.44%	(3,602.72)
General Plant - Depreciable	397	DGU	1,047,122.95	-	1,047,122.95	5.34%	4.86%	55,916.37	50,890.18	(5,026.19)	13.44%	(675.58)
General Plant - Depreciable	397	IDU	5,473,416.54	-	5,473,416.54	5.03%	4.75%	275,312.85	259,987.29	(15,325.57)	100.00%	(15,325.57)
General Plant - Depreciable	397	OR	35,801,956.17	-	35,801,956.17	5.58%	6.28%	1,997,749.15	2,248,362.85	250,613.69	0.00%	-
General Plant - Depreciable	397	SE	6,215.27	-	6,215.27	5.03%	4.75%	312.63	295.23	(17.40)	6.87%	(1.19)
General Plant - Depreciable	397	SG	1,693,829.79	-	1,693,829.79	3.75%	5.30%	63,518.62	89,772.98	26,254.36	6.49%	1,703.19
General Plant - Depreciable	397	SG	1,213,848.29	-	1,213,848.29	3.89%	4.15%	47,218.70	50,374.70	3,156.01	6.49%	204.74
General Plant - Depreciable	397	SG	1,247,183.96	-	1,247,183.96	4.97%	3.93%	61,985.04	49,014.33	(12,970.71)	6.49%	(841.44)
General Plant - Depreciable	397	SG	10,641,261.74	-	10,641,261.74	5.03%	4.75%	535,255.47	505,459.93	(29,795.53)	6.49%	(1,932.91)
General Plant - Depreciable	397	SG	5,309,520.00	-	5,309,520.00	5.34%	4.86%	283,528.37	258,042.67	(25,485.70)	6.49%	(1,653.32)
General Plant - Depreciable	397	SG	13,264,204.57	-	13,264,204.57	5.58%	6.28%	740,142.62	832,992.05	92,849.43	6.49%	6,023.39
General Plant - Depreciable	397	SO	13,997,926.41	-	13,997,926.41	5.03%	4.75%	704,095.70	664,901.50	(39,194.19)	6.12%	(2,398.90)
General Plant - Depreciable	397	SO	129,596.64	-	129,596.64	5.34%	4.86%	6,920.46	6,298.40	(622.06)	6.12%	(38.07)
General Plant - Depreciable	397	SO	33,917,274.87	-	33,917,274.87	5.58%	6.28%	1,892,583.94	2,130,004.86	237,420.92	6.12%	14,531.47
General Plant - Depreciable	397	UT	20,972,581.22	-	20,972,581.22	5.03%	4.75%	1,054,920.84	996,197.61	(58,723.23)	0.00%	-
General Plant - Depreciable	397	WA	8,448,923.00	-	8,448,923.00	3.75%	5.30%	316,834.61	447,792.92	130,958.31	0.00%	-
General Plant - Depreciable	397	WYP	13,060,549.16	-	13,060,549.16	5.34%	4.86%	697,433.33	634,742.69	(62,690.64)	0.00%	-
General Plant - Depreciable	397	WYU	1,857,973.76	-	1,857,973.76	5.34%	4.86%	99,215.80	90,297.52	(8,918.27)	0.00%	-
TOTAL GNL PLANT DEPRECIABLE			398,574,063.17	(45,766,393.01)	352,807,670.16	3.99%	4.54%	14,061,217.84	16,009,227.71	1,948,009.86		84,557.23
General Plant - Vehicles	392	CA	276,974.91	-	276,974.91	3.24%	2.30%	8,973.99	6,370.42	(2,603.56)	0.00%	-
General Plant - Vehicles	392	CA	313,402.26	-	313,402.26	6.09%	5.04%	19,086.20	15,795.47	(3,290.72)	0.00%	-
General Plant - Vehicles	392	CA	469,477.76	-	469,477.76	10.90%	6.31%	51,173.08	29,624.05	(21,549.03)	0.00%	-
General Plant - Vehicles	392	CN	12,977.97	-	12,977.97	10.78%	8.92%	1,399.03	1,157.63	(241.39)	3.78%	(9.12)
General Plant - Vehicles	392	DGP	2,022.76	-	2,022.76	2.25%	2.52%	45.51	50.97	5.46	0.00%	-
General Plant - Vehicles	392	DGP	14,658.20	-	14,658.20	6.31%	6.65%	924.93	974.77	49.84	0.00%	-
General Plant - Vehicles	392	DGP	27,049.58	-	27,049.58	6.46%	7.34%	1,747.40	1,985.44	238.04	0.00%	-
General Plant - Vehicles	392	DGP	145,201.68	-	145,201.68	8.76%	4.67%	12,719.67	6,780.92	(5,938.75)	0.00%	-
General Plant - Vehicles	392	DGP	39,560.88	-	39,560.88	12.75%	5.89%	5,044.01	2,330.14	(2,713.88)	0.00%	-
General Plant - Vehicles	392	DGU	29,778.33	-	29,778.33	1.75%	2.51%	521.12	747.44	226.32	13.44%	30.42
General Plant - Vehicles	392	DGU	32,613.04	-	32,613.04	3.55%	3.27%	1,157.76	1,066.45	(91.32)	13.44%	(12.27)

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Witness: Kathryn C. Hymas

PACIFICORP

IDAHO Depreciation Rate Comparison - FYMar02

PLANT	ACCT	AF	PLANT-IN-SERVICE			DEP RATE		TOTAL COMPANY DEPRECIATION			IDAHO ALLOCATION	
			TOTAL	NONDEP	NET	EXISTING	PROPOSED	EXISTING	PROPOSED	DIFFERENCE	FACTOR	AMOUNT
General Plant - Vehicles	392	DGU	757,450.59	-	757,450.59	4.62%	5.64%	34,994.22	42,720.21	7,726.00	13.44%	1,038.47
General Plant - Vehicles	392	DGU	191,620.22	-	191,620.22	5.47%	6.69%	10,481.63	12,819.39	2,337.77	13.44%	314.22
General Plant - Vehicles	392	DGU	44,694.29	-	44,694.29	8.76%	4.67%	3,915.22	2,087.22	(1,828.00)	13.44%	(245.71)
General Plant - Vehicles	392	DGU	12,834.33	-	12,834.33	12.75%	5.89%	1,636.38	755.94	(880.44)	13.44%	(118.34)
General Plant - Vehicles	392	IDU	530,628.60	-	530,628.60	1.75%	2.51%	9,286.00	13,318.78	4,032.78	100.00%	4,032.78
General Plant - Vehicles	392	IDU	1,474,699.87	-	1,474,699.87	4.62%	5.64%	68,131.13	83,173.07	15,041.94	100.00%	15,041.94
General Plant - Vehicles	392	IDU	1,662,312.04	-	1,662,312.04	5.47%	6.69%	90,928.47	111,208.68	20,280.21	100.00%	20,280.21
General Plant - Vehicles	392	OR	2,103,293.24	-	2,103,293.24	2.25%	2.52%	47,324.10	53,002.99	5,678.89	0.00%	-
General Plant - Vehicles	392	OR	5,204,299.84	-	5,204,299.84	6.31%	6.65%	328,391.32	346,085.94	17,694.62	0.00%	-
General Plant - Vehicles	392	OR	5,206,833.03	-	5,206,833.03	10.78%	8.92%	561,296.60	464,449.51	(96,847.09)	0.00%	-
General Plant - Vehicles	392	SE	5,383.91	-	5,383.91	1.75%	2.51%	94.22	135.14	40.92	6.87%	2.81
General Plant - Vehicles	392	SE	57,420.98	-	57,420.98	4.62%	5.64%	2,652.85	3,238.54	585.69	6.87%	40.21
General Plant - Vehicles	392	SE	330,408.14	-	330,408.14	5.47%	6.69%	18,073.33	22,104.30	4,030.98	6.87%	276.77
General Plant - Vehicles	392	SG	219,077.11	-	219,077.11	1.75%	2.51%	3,833.85	5,498.84	1,664.99	6.49%	108.01
General Plant - Vehicles	392	SG	141,005.85	-	141,005.85	2.25%	2.52%	3,172.63	3,553.35	380.72	6.49%	24.70
General Plant - Vehicles	392	SG	26,302.47	-	26,302.47	2.30%	2.67%	604.96	702.28	97.32	6.49%	6.31
General Plant - Vehicles	392	SG	44,566.96	-	44,566.96	3.55%	3.27%	1,582.13	1,457.34	(124.79)	6.49%	(8.10)
General Plant - Vehicles	392	SG	1,304,562.74	-	1,304,562.74	4.62%	5.64%	60,270.80	73,577.34	13,306.54	6.49%	863.23
General Plant - Vehicles	392	SG	2,143,684.35	-	2,143,684.35	5.47%	6.69%	117,259.53	143,412.48	26,152.95	6.49%	1,696.61
General Plant - Vehicles	392	SG	57,885.35	-	57,885.35	6.09%	5.04%	3,525.22	2,917.42	(607.80)	6.49%	(39.43)
General Plant - Vehicles	392	SG	514,170.43	-	514,170.43	6.31%	6.65%	32,444.15	34,192.33	1,748.18	6.49%	113.41
General Plant - Vehicles	392	SG	404,107.32	-	404,107.32	6.46%	7.34%	26,105.33	29,661.48	3,556.14	6.49%	230.70
General Plant - Vehicles	392	SG	1,685.24	-	1,685.24	7.09%	6.89%	119.48	116.11	(3.37)	6.49%	(0.22)
General Plant - Vehicles	392	SG	416,697.54	-	416,697.54	8.76%	4.67%	36,502.70	19,459.78	(17,042.93)	6.49%	(1,105.62)
General Plant - Vehicles	392	SG	364,866.01	-	364,866.01	10.78%	8.92%	39,332.56	32,546.05	(6,786.51)	6.49%	(440.26)
General Plant - Vehicles	392	SG	15,406.72	-	15,406.72	10.90%	6.31%	1,679.33	972.16	(707.17)	6.49%	(45.88)
General Plant - Vehicles	392	SG	335,973.14	-	335,973.14	12.49%	7.11%	41,963.05	23,887.69	(18,075.35)	6.49%	(1,172.60)
General Plant - Vehicles	392	SG	844,758.26	-	844,758.26	12.75%	5.89%	107,706.68	49,756.26	(57,950.42)	6.49%	(3,759.40)
General Plant - Vehicles	392	SO	1,398,506.53	-	1,398,506.53	1.75%	2.51%	24,473.86	35,102.51	10,628.65	6.12%	650.53
General Plant - Vehicles	392	SO	5,271.50	-	5,271.50	2.25%	2.52%	118.61	132.84	14.23	6.12%	0.87
General Plant - Vehicles	392	SO	1,572,202.95	-	1,572,202.95	4.62%	5.64%	72,635.78	88,672.25	16,036.47	6.12%	981.52
General Plant - Vehicles	392	SO	1,664,343.24	-	1,664,343.24	5.47%	6.69%	91,039.58	111,344.56	20,304.99	6.12%	1,242.78
General Plant - Vehicles	392	SO	163,790.01	-	163,790.01	6.31%	6.65%	10,335.15	10,892.04	556.89	6.12%	34.08
General Plant - Vehicles	392	SO	35,464.13	-	35,464.13	8.76%	4.67%	3,106.66	1,656.17	(1,450.48)	6.12%	(88.78)
General Plant - Vehicles	392	SO	955,666.97	-	955,666.97	10.78%	8.92%	103,020.90	85,245.49	(17,775.41)	6.12%	(1,087.95)
General Plant - Vehicles	392	SO	111,558.24	-	111,558.24	12.75%	5.89%	14,223.68	6,570.78	(7,652.90)	6.12%	(468.40)
General Plant - Vehicles	392	UT	4,605,459.65	-	4,605,459.65	1.75%	2.51%	80,595.54	115,597.04	35,001.49	0.00%	-
General Plant - Vehicles	392	UT	12,609,748.98	-	12,609,748.98	4.62%	5.64%	582,570.40	711,189.84	128,619.44	0.00%	-
General Plant - Vehicles	392	UT	11,224,936.08	-	11,224,936.08	5.47%	6.69%	614,004.00	750,948.22	136,944.22	0.00%	-
General Plant - Vehicles	392	WA	372,709.54	-	372,709.54	2.30%	2.67%	8,572.32	9,951.34	1,379.03	0.00%	-
General Plant - Vehicles	392	WA	1,118,673.13	-	1,118,673.13	6.46%	7.34%	72,266.28	82,110.61	9,844.32	0.00%	-
General Plant - Vehicles	392	WA	1,088,294.60	-	1,088,294.60	12.49%	7.11%	135,928.00	77,377.75	(58,550.25)	0.00%	-
General Plant - Vehicles	392	WYP	1,369,130.98	-	1,369,130.98	3.55%	3.27%	48,604.15	44,770.58	(3,833.57)	0.00%	-
General Plant - Vehicles	392	WYP	2,074,973.45	-	2,074,973.45	8.76%	4.67%	181,767.67	96,901.26	(84,866.41)	0.00%	-
General Plant - Vehicles	392	WYP	1,922,940.79	-	1,922,940.79	12.75%	5.89%	245,174.95	113,261.21	(131,913.74)	0.00%	-
General Plant - Vehicles	392	WYU	514,238.80	-	514,238.80	3.55%	3.27%	18,255.48	16,815.61	(1,439.87)	0.00%	-
General Plant - Vehicles	392	WYU	818,172.76	-	818,172.76	8.76%	4.67%	71,671.93	38,208.67	(33,463.27)	0.00%	-
General Plant - Vehicles	392	WYU	663,767.72	-	663,767.72	12.75%	5.89%	84,630.38	39,095.92	(45,534.47)	0.00%	-
General Plant - Vehicles	396	CA	2,190,660.26	-	2,190,660.26	5.45%	4.13%	119,390.98	90,475.95	(28,915.03)	0.00%	-

Exhibit No. 1, Pg. 3 of 4
Case No. ___
Witness: Kathryn C. Hymas

PACIFICORP
IDAHO Depreciation Rate Comparison - FYMar02

PLANT	ACCT	AF	PLANT-IN-SERVICE			DEP RATE		TOTAL COMPANY DEPRECIATION			IDAHO ALLOCATION	
			TOTAL	NONDEP	NET	EXISTING	PROPOSED	EXISTING	PROPOSED	DIFFERENCE	FACTOR	AMOUNT
General Plant - Vehicles	396	DGP	6,555.64	-	6,555.64	4.25%	5.11%	278.61	334.99	56.38	0.00%	-
General Plant - Vehicles	396	DGP	1,286,172.67	-	1,286,172.67	6.40%	3.93%	82,315.05	50,546.59	(31,768.46)	0.00%	-
General Plant - Vehicles	396	DGU	695,788.75	-	695,788.75	4.06%	5.81%	28,249.02	40,425.33	12,176.30	13.44%	1,636.64
General Plant - Vehicles	396	IDU	5,630,838.87	-	5,630,838.87	4.06%	6.34%	228,612.06	357,141.89	128,529.83	100.00%	128,529.83
General Plant - Vehicles	396	OR	19,920,029.39	-	19,920,029.39	4.25%	5.67%	846,601.25	1,129,571.52	282,970.27	0.00%	-
General Plant - Vehicles	396	SE	160,302.88	-	160,302.88	4.06%	5.81%	6,508.30	9,313.60	2,805.30	6.87%	192.61
General Plant - Vehicles	396	SG	3,423,321.07	-	3,423,321.07	4.06%	5.81%	138,986.84	198,894.95	59,908.12	6.49%	3,886.40
General Plant - Vehicles	396	SG	1,223,707.73	-	1,223,707.73	4.25%	5.11%	52,007.58	62,531.47	10,523.89	6.49%	682.71
General Plant - Vehicles	396	SG	362,566.41	-	362,566.41	6.21%	7.16%	22,515.37	25,959.75	3,444.38	6.49%	223.45
General Plant - Vehicles	396	SG	6,777,591.96	-	6,777,591.96	6.40%	3.93%	433,765.89	266,359.36	(167,406.52)	6.49%	(10,860.10)
General Plant - Vehicles	396	SG	15,167.19	-	15,167.19	6.69%	6.05%	1,014.69	917.61	(97.07)	6.49%	(6.30)
General Plant - Vehicles	396	SO	2,239,407.83	-	2,239,407.83	4.06%	5.81%	90,919.96	130,109.59	39,189.64	6.12%	2,398.62
General Plant - Vehicles	396	SO	918,116.00	-	918,116.00	4.25%	5.11%	39,019.93	46,915.73	7,895.80	6.12%	483.27
General Plant - Vehicles	396	SO	221,266.57	-	221,266.57	6.40%	3.93%	14,161.06	8,695.78	(5,465.28)	6.12%	(334.51)
General Plant - Vehicles	396	UT	29,562,004.04	-	29,562,004.04	4.06%	6.14%	1,200,217.36	1,814,479.65	614,262.29	0.00%	-
General Plant - Vehicles	396	WA	5,484,951.05	-	5,484,951.05	6.21%	7.59%	340,615.46	416,461.29	75,845.83	0.00%	-
General Plant - Vehicles	396	WYP	6,932,062.80	-	6,932,062.80	6.40%	4.54%	443,652.02	314,686.63	(128,965.39)	0.00%	-
General Plant - Vehicles	396	WYU	2,372,587.74	-	2,372,587.74	6.40%	4.20%	151,845.62	99,668.21	(52,177.41)	0.00%	-
TOTAL GNL PLANT VEHICLES			159,493,294.84	-	159,493,294.84	5.30%	5.73%	8,459,772.92	9,143,028.93	683,256.00		165,241.16
TOTAL GENERAL PLANT			558,067,358.01	(45,766,393.01)	512,300,965.00	4.40%	4.91%	22,520,990.77	25,152,256.63	2,631,265.87		249,798.39
Mining Plant		SE	260,565,862.27	(85,034,983.27)	175,530,879.00	5.55%	5.98%	9,736,013.00	10,490,705.00	754,692.00	6.87%	51,817.98
TOTAL COMPANY			11,702,886,906.90	(230,274,430.97)	11,472,612,475.93	3.11%	3.11%	357,232,553.03	356,500,406.65	(732,146.38)		612,169.95

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

In the Matter of the Application of	) Case No. __________
PACIFICORP for an Order Authorizing a	)
Change in Depreciation Rates Applicable to	) Direct Testimony of Donald S. Roff
Electric Property.	)

PACIFICORP

October, 2002

Introduction and Background

Q. Please state your name, occupation, business address, employer and job title.

A. My name is Donald S. Roff. I am a Director with the public accounting firm of Deloitte & Touche LLP. My business address is 2200 Ross Avenue, Dallas, Texas 75201.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of PacifiCorp ("the Company").

Q. Please state your qualifications.

A. My qualifications are described on Exhibit No. 2.

Q. Have you previously testified before this or any other regulatory body?

A. Yes. A list of my regulatory appearances and related jurisdictions is attached as Exhibit No. 3.

Q. What is the purpose of your testimony?

A. I have been asked by PacifiCorp to testify as to the recommended depreciation rates to be used by the Company for the accrual of depreciation expense.

Q. Please summarize your testimony.

A. Based upon my depreciation study, a copy of which is attached to my Direct Testimony as Exhibit No. 4, conducted as of March 31, 2002, I recommend changes to the depreciation rates currently in use, as illustrated by the following comparison:

Function	Existing %	Recommended %
Steam Production Plant	2.93	3.34
Hydraulic Production Plant	2.93	3.28
Other Production Plant	2.88	3.25
Transmission Plant	2.03	2.18
Distribution Plant	3.70	2.99
General Plant	4.40	4.91
Mining Operations	5.55	5.98
Total Electric Plant	3.11	3.11

This summary is taken from Table A, page 3 of Exhibit No. 4.

Application of my recommended rates to the March 31, 2002 depreciable balances results in a decrease in annual depreciation expense of $732,000. The following sections of my testimony discuss the depreciation study procedure, life analysis, interim activity, salvage and cost of removal analysis, and the results for Steam, Hydraulic and Other Production Plant, Transmission, Distribution and General Plant, and Mining Operations and my recommendations.

Q. What are the primary reasons for the minimal change in depreciation that you recommend?

A. There are two factors that influence the level of depreciation expense change that I recommend. The first factor is recognition of less negative net salvage for Transmission and Distribution Plant asset categories, reflective of current experience. The second element is additional investment installed since the prior study.

Depreciation Study Procedure

Q. What is depreciation?

A. The most widely recognized accounting definition of depreciation is that of the American Institute of Certified Public Accountants, which states:

> "Depreciation accounting is a system of accounting which aims to distribute the cost or other basic value of tangible capital assets, less salvage (if any), over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation."[1]

Q. What is the significance of this definition?

A. This definition of depreciation accounting forms the accounting framework under which my depreciation study was conducted. Several aspects of this definition are particularly significant. Salvage (net salvage) is to be recognized. The allocation of costs is over the useful life of the assets. Grouping of assets is permissible. Depreciation accounting is not a valuation process. And the cost allocation must be both systematic and rational.

Q. Please explain the importance of the terms "systematic and rational".

A. Systematic implies the use of a formula, and the formula used for calculating the recommended depreciation rates is shown on Page 15 of Exhibit No. 4. Rational

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1 Accounting Research Bulletin No. 43, Chapter 9, Paragraph 5 (June 1953).

means that the pattern of depreciation, in this case, the depreciation rate itself, must match either the pattern of revenues produced by the asset, or match the consumption of the asset. Since revenues are determined through regulation and are expected to continue to be so determined, asset consumption must be directly measured and reflected in depreciation rates. This measurement of asset consumption is accomplished by conducting a depreciation study.

Q. Are there other definitions of depreciation?

A. Yes. The Federal Energy Regulatory Commission Uniform System of Accounts, followed by the Company, provides a series of definitions related to depreciation as shown on Page 7 of Exhibit No. 4. These definitions of depreciation make reference to asset consumption, and therefore relate very well to the accounting framework for depreciation. These definitions form the regulatory framework under which my depreciation study was conducted. Remaining life rates are recommended, which depreciation rates provide for full recovery of net investment adjusted for net salvage over the future useful life of each asset category, and are consistent with past practice.

Q. How does your depreciation study recognize asset consumption?

A. Asset consumption in my depreciation study is recognized in two different ways, depending upon the type of asset. For mass property, asset consumption (retirement dispersion) is defined by the use of Iowa type curves and related average service lives. For life span property (power plants), asset consumption is recognized through the use of interim activity factors, which provide a form of retirement dispersion.

Q. What is retirement dispersion?

A. Retirement dispersion merely recognizes that groups of assets have individual assets of different lives, i.e., each asset retires at differing ages. Retirement dispersion is the scattering of retirements by age around the average service life for each group of assets.

Q. Please describe how these elements were determined and utilized in your depreciation study.

A. A depreciation study consists of four distinct yet related phases - data collection, analysis, evaluation and rate calculation. Data collection refers to the gathering of historical accounting information for use in the other phases. PacifiCorp personnel assisted with this effort, and provided a large amount of historical accounting data. Analysis refers to the statistical processing of the data collected in the first phase. There are two separate analysis procedures, one for life, and one for salvage and cost of removal. The evaluation phase incorporates the information developed in the data collection and analysis phases, to determine the applicability of the historical relationships developed in these phases to the future. The rate calculation phase merely utilizes the parameters developed in the other phases in the computation of the recommended depreciation rates.

Q. What are the parameters used in the calculation of your recommended depreciation rates?

A. The parameters are the estimated retirement date for Production Plants or average service life for Transmission, Distribution and General Plant; retirement dispersion defined by interim retirement factors for Production Plant and by Iowa curves for the mass accounts; and interim and terminal net salvage factors for Production Plant and terminal net salvage factors for the mass accounts. Also used are the depreciable plant balance, the accumulated provision for depreciation, and the average remaining life. How these factors are used in the calculation is discussed on Pages 15 and 16 of Exhibit No. 4 Individual parameters are shown on Schedule 3 of Exhibit No. 4.

Life Analysis

Q. Please explain the life analysis phase of your study of production plant.

A. There are two parts to the life analysis phase of my study of Production Plant. The first is the determination of the estimated retirement date for each plant suitable for the calculation of depreciation rates. The second part is the determination of interim retirement ratios and interim addition factors from an analysis of historical experience.

Q. What was the basis for the retirement dates used in your depreciation study of production plant?

A. These retirement dates were provided to me by PacifiCorp planning personnel, and are contained on Exhibit No. 4, Schedule 3. It is my understanding that these estimated retirement dates give consideration to the age of the plant, it's operating characteristics, and economic and environmental constraints.

Q. Are these dates reasonable and consistent with your knowledge and experience?

A. Yes. These retirement dates produce life spans, which are reasonable and consistent with my experience. It is my understanding that these dates reflect the current best estimate of when the generating units will retire, giving due consideration to each unit's age, location, operating characteristics and expected future usage, and therefore represent the appropriate period over which the allocation of cost should occur.

Q. Please describe the life analysis procedure utilized for non-production plant asset categories.

A. For most asset categories, PacifiCorp maintains vintaged accounting records, that is, the age of property retired and property surviving is known. The exception is Account 370, Meters and the Distribution line accounts in Utah and Idaho (Account 364 – Account 373). For the aged asset categories the actuarial method of life analysis was utilized. For the unaged asset categories, the Simulated Plant Record ("SPR") method was utilized.

Q. Please Describe Actuarial Analysis.

A. Actuarial analysis uses the age information contained in the historical property records to determine life tables (survivor curves) for various bands of experience. These plots of percent surviving as a function of age are then compared to standard distributions (Iowa curves) to arrive at an historical average service life and curve shape.

Q. Please describe SPR analysis.

A. SPR analysis determines retirement dispersion and average service life combinations for various bands of years that best match the actual retirements and/or balances for each asset category. The simulated balances procedure consists of applying survivor ratios (portion surviving at each age) from Iowa-type dispersion patters in order to calculate annual balances, and then comparing the calculated balances with the actual balances for several periods, followed by statistical comparisons of differences in balances. The simulated retirements procedure is similar, except that the retirement frequency rates of the Iowa patterns are utilized to calculate annual retirements, and the comparisons are to actual retirements rather than to balances. Tabulations of the best ranking curves were made and this became the starting point for the evaluation phase of my depreciation study.

Interim Activity

Q. What are interim retirements?

A. Interim retirements are the retirements of plant components between the date of original installation and the date of final retirement of a plant or unit.

Q. What are interim additions?

A. Interim additions are the replacement of retired plant components, or the addition of new plant components not originally necessary, between the date of original installation and the date of final retirement of a plant or unit.

Q. Is the analysis of interim activity, that is, both interim additions and interim retirements, an accepted analytical procedure?

A. Yes. These accounting histories are readily available, sufficient, and provide useful information upon which to base meaningful conclusions. A description of this analysis process is provided in Exhibit No. 4 at Pages 10 and 11.

Q. Why should interim additions and retirements be included in the calculation of depreciation rates for production plant?

A. Interim retirements occur over the life of a production unit as items are replaced or retired. This is clearly evident from a review of historical investment experience. Recognition of the effect of these interim retirements in the depreciation rate calculation is necessary to ensure that these interim retirements are fully depreciated by the time they occur. Similarly, interim additions occur over the life of a production unit as items are replaced or new items are installed. This activity is also clearly evident from a review of historical investment experience. Recognition of the effect of these interim additions in the depreciation rate calculation is necessary because the estimated retirement dates cannot occur without the replacement activity, and the estimated retirement dates assume this activity will occur.

Q. What interim activity factors were developed in your depreciation study?

A. The interim retirement ratios and interim addition factors utilized in my depreciation study are shown in Exhibit No. 4, Schedule 3, pages 65 and 66, columns 4 and 5.

Q. Were these factors used in the calculation of your recommended depreciation rates for production plant?

A. My recommended depreciation rates for Production Plant include no interim addition factor, but do include interim retirements.

Q. Why were interim additions excluded?

A. While it would be appropriate to include interim additions, they were excluded from the depreciation rate calculations for two reasons. The primary reason was to mitigate the effect of the change in depreciation rates. The second reason was to limit, to the extent possible, the issues before the Commission in this case.

Q. What would be the effect of including all interim additions in the depreciation rate calculation?

A. The recommended depreciation rates for Production Plant would have been substantially higher.

Q. What is the effect on the annual depreciation rate of ignoring these interim additions?

A. Initially, the depreciation rate would be slightly lower, but would increase at each recalculation. Exhibit No. 5 has been prepared to illustrate this effect. Of particular interest is the pattern of depreciation rates shown in Column 13. This ever-increasing pattern of depreciation rates would be appropriate only if asset consumption is ever increasing.

Salvage and Cost of Removal Analysis

Q. Please discuss the cost of removal and salvage analysis portion of your study of production plant.

A. There are two separate components of cost of removal and salvage for Production Plant: interim and terminal. Interim net salvage refers to the cost of removal net of salvage related to interim retirements. Terminal net salvage refers to the net demolition cost of a plant or unit at final retirement. Interim net salvage factors were determined based upon an analysis of historical experience. Terminal net salvage factors were projected based upon a review of the site-specific demolition cost estimates of others.

Q. How were the interim net salvage factors for production plant determined?

A. Primary account summaries of retirements, salvage and cost of removal were provided by PacifiCorp personnel. I examined the ratio of salvage, cost of removal and net salvage to retirements and looked at the trends over time. I then selected an interim net salvage factor for each primary account.

Q. How were the terminal net salvage factors for production plant determined?

A. I have collected the site-specific demolition cost estimates of over 500 units, which are in the public record. For each unit I have computed the net demolition cost per kW of generating capacity by fuel type. This average figure is about $50/kW in 2001 price levels for coal-fired units. Exhibit No. 6, provides a summary of the site-specific demolition cost studies. I conservatively used this $50/kW for coal units to recognize the ongoing environmental control facilities additions. This number is conservative because additional pollution control requirements are expected which will increase this unit cost. The net demolition amounts were then allocated to accounts on the basis of plant investment, and used in the depreciation rate calculations. A similar process was used for the units that are not coal-fired.

Steam Production Plant Results

Q. Please summarize your results for steam production plant.

A. Use of the parameters described above results in a composite depreciation rate of 3.34 percent, which produces an annual depreciation expense increase of $17,100,000, or about 14 percent above the existing rate.

Q. What is the reason for this increase in depreciation expense?

A. The primary reason for the increase is additional investment installed since the prior study, which must be recovered over a period shorter than the original life span.

Hydraulic Production Plant Results

Q. Please discuss the results of your depreciation study for hydraulic production plant.

A. Retirement dates were tied to license expiration dates or expected license renewal dates. Interim activity has been limited, and no interim additions were included, although a figure greater than one is justified by historical experience. Zero terminal net salvage has been used, with the exception of the Condit and American Fork Plant. The composite depreciation rate for Hydraulic Production Plant increased from 2.93 percent to 3.28 percent, primarily due to the effect of some relatively new investments. Note that this depreciation rate comparison incorporates the removal cost provision for Condit and American Fork. The net change in annual depreciation for Hydraulic Production Plant is approximately $1,650,000.

Other Production Plant Results

Q. Please discuss the results of your study of other production plant.

A. The composite depreciation rate for Other Production Plant increased from 2.88 percent to 3.25 percent, reflecting little change to existing parameters. The change produced an increase in annual depreciation expense of $733,000, or about 13 percent, primarily due to the addition of the Wyoming Wind Farm.

Transmission, Distribution and General Plant

Q. Please discuss the life analysis procedure for transmission, distribution and general plant.

A. For most asset categories the age of both surviving and retired property is known, and actuarial analysis was utilized for these property groups. Actuarial analysis is described on Pages 11 and 12 of Exhibit No. 4. For some asset groups, the age of property retired is not known, and a Simulated Plant Record Analysis was performed. The SPR method determines retirement dispersion and average service life combinations for various bands of years that best match the actual retirements and balances for each asset category.

Q. What are Iowa-type curves?

A. The Iowa-type curves were devised empirically over 60 years ago by the Engineering Research Institute at what is now Iowa State University to provide a set of standard definitions of retirement dispersion. Retirement dispersion merely recognizes that groups of assets have individual assets of different lives, i.e., each asset retires at differing ages. Retirement dispersion is the scattering of retirements by age around the average service life for each group of assets. Standard dispersion patterns are useful because they make calculations of the remaining life of existing property possible and allow life characteristics to be compared.

The Engineering Research Institute collected dated retirement information on many types of industrial and utility property and devised empirical curves that matched the range of patterns found. A total of 18 curves were defined. There were six left-skewed, seven symmetrical and five right-skewed curves, varying from wide to narrow dispersion patterns. The Iowa-curve naming convention allows the analyst to relate easily to the patterns. The left-skewed curves are known as the "L series", the symmetrical as the "S series" and the right-skewed as the "R series." A number identifies the range of dispersion. A low number represents a wide pattern and a high number a narrow pattern. The combination of one letter and one number defines a unique dispersion pattern.

Q. How were the Iowa curve shapes and average service life selections made?

A. Summaries of the individual asset category life analysis indications were prepared and discussed with PacifiCorp personnel. Anomalies and trends were identified and engineering and operations input was requested where necessary. A single average service life and Iowa curve was selected for each asset category reflecting the combination of the historical results and the additional information obtained from the engineering, accounting and operations personnel. This process is a part of the evaluation phase of the depreciation study.

Q. Please explain the salvage and cost of removal analysis.

A. Annual salvage amounts, cost of removal and retirements were provided by functional group for the period 1990 though 2002. Annual salvage, cost of removal and net salvage percentages were calculated by dividing by the retirement amounts. Rolling and shrinking bands were also developed to illustrate trends.

Q. Please summarize your results for transmission, distribution and general plant.

A. In general, average service lives have increased, and net salvage factors have become less negative. The composite depreciation rate for Transmission Plant increased from 2.03 percent to 2.18 percent, an annual expense increase of about $3,190,000, or about 7 percent. The primary reasons are slightly decreased average service lives and slightly more negative net salvage.

The composite depreciation rate for Distribution Plant decreased from 3.70 percent to 2.99 percent, an annual expense decrease of over $26,700,000, or about 19 percent. Increased average service lives were compounded by less negative net salvage.

The composite depreciation rate for General Plant increased from 4.40 percent to 4.91 percent, an annual expense increase of roughly $2,600,000, or nearly 12 percent. The primary reason for the increase is the effect of less positive net salvage.

Mining Operations

Q. Please summarize your results for mining operations.

A. Certainly. The composite depreciation rate increased from 5.55 percent to 5.98 percent. Average service lives have both increased and decreased, as have net salvage allowances.

Q. What is the total change in annual depreciation indicated by your study?

A. At the total Company depreciable investment level, the decrease in annual depreciation expense indicated by my study is about $732,000.

Recommendations

Q. Please summarize your recommendations.

A. I recommend that PacifiCorp adopt the depreciation rates shown in Column 12 of Schedule 1 of Exhibit No. 4, and that this Commission approve their use. I base this recommendation on the fact that I have conducted a comprehensive depreciation study, giving appropriate recognition to historical experience, recent trends and Company expectations. My study results in a fair and reasonable level of depreciation expense which, when incorporated into a revenue stream, will provide the Company with adequate capital recovery until such time as a new depreciation study indicates a need for change.

Q. Does this complete your direct testimony?

A. Yes, it does.

Case No. __________
Exhibit 2
Witness: Donald S. Roff

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

PACIFICORP

Exhibit Accompanying Direct Testimony of Donald S. Roff

Qualifications

October, 2002

Academic Background

Donald S. Roff graduated from Rensselaer Polytechnic Institute with a Bachelor of Science degree in Management Engineering in 1972.

Mr. Roff has also received specialized training in the area of depreciation from Western Michigan University's Institute of Technological Studies. This training involved three forty-hour seminars on depreciation entitled "Fundamentals of Depreciation", "Fundamentals of Service Life Forecasting" and "Making a Depreciation Study" and included such topics as accounting for depreciation, estimating service life, and estimating salvage and cost of removal.

Employment and Professional Experience

Following graduation, Mr. Roff was employed for eleven and one-half years by Gilbert Associates, Inc., as an engineer in the Management Consulting Division. In this capacity, he held positions of increasing responsibility related to the conduct and preparation of various capital recovery and valuation assignments.

In 1984, Mr. Roff was employed by Ernst & Whinney and was involved in several depreciation rate studies and utility consulting assignments.

In 1985, Mr. Roff joined Deloitte Haskins & Sells (DH&S), which, in 1989, merged with Touche Ross & Co. to form Deloitte & Touche. In 1995, Mr. Roff was appointed as a Director with Deloitte & Touche.

During his tenure with Gilbert Associates, Inc., Ernst & Whinney, DH&S and Deloitte & Touche, Mr. Roff has participated in or directed depreciation studies for electric, gas, water and steam heat utilities, pipelines, railroad and telecommunication companies in over 30 states, several Canadian provinces and Puerto Rico. This work requires an in-depth knowledge of depreciation accounting and regulatory principles, mortality analysis techniques and financial practices. At these firms, Mr. Roff has had varying degrees of responsibility for valuation studies, development of depreciation accrual rates, consultation on the unitization of property records, and other studies concerned with the inspection and appraisals of utility property, preparation of rate case testimony and support exhibits, data responses and rebuttal testimony, in addition to appearing as an expert witness.

Industry and Technical Affiliations

Mr. Roff is a registered Professional Engineer in Pennsylvania (by examination).

Mr. Roff is a member of the Society of Depreciation Professionals and a Certified Depreciation Professional, and a Technical Associate of the American Gas Association (A.G.A.) Depreciation Committee. He currently serves as the lead instructor for the A.G.A.'s Principles of Depreciation Course.

Case No. __________
Exhibit No. 3
Witness: Donald S. Roff

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

PACIFICORP

Exhibit Accompanying Direct Testimony of Donald S. Roff

Testimony Experience

October, 2002

DONALD S. ROFF

TESTIMONY EXPERIENCE

CASE NO.	DATE	COMPANY	JURISDICTION	SUBJECT
Docket No. 93-3005	July 1993	Southwest Gas Corporation	Nevada	Gas Depreciation Rates
Docket No. 93-3025	July 1993	Southwest Gas Corporation	Nevada	Gas Depreciation Rates
Docket No. 12820	June 1994	Central Power and Light Company	Texas	Electric Depreciation Rates
Case No. U-10380	Dec 1994	Consumers Power Company	Michigan	Gas Depreciation Rates and Accounting
Cause No. 39938	April 1995	Indianapolis Power & Light Company	Indiana	Electric Depreciation Rates
Case No. U-10754	July 1995	Consumers Power Company	Michigan	Electric Depreciation Rates and Accounting
Docket No. 13369	Aug 1995	West Texas Utilities Company	Texas	Electric Depreciation Rates
Docket No. 95-02116	Sept 1995	Chattanooga Gas Company	Tennessee	Gas Depreciation Rates
Docket No. 95-715-G	Oct 1995	Piedmont Natural Gas Company	South Carolina	Gas Depreciation Rates
Docket No. 14965	Dec 1995	Central Power and Light Company	Texas	Electric Depreciation Rates
Cause No. 40395 (I)	Feb 1996	Wabash Valley Power Association, Inc.	Indiana	Electric Depreciation Rates
GUD NO. 8664	Oct 1996	Lone Star Pipeline Company	Texas	Gas Depreciation Rates
Docket No. 96-360-U	Nov 1996	Entergy Arkansas Inc.	Arkansas	Electric Depreciation Rates
Docket No. 16705	Nov 1996	Entergy Gulf States Inc.	Texas	Electric Depreciation Rates/Competitive Issues
Docket No. ER-97-394	Mar 1997	Missouri Public Service	Missouri	Electric Depreciation Rates/Competitive Issues
Docket No. U-22092	Mar 1997	Entergy Gulf States Inc.	Louisiana	Electric Depreciation Rates/Competitive Issues
Docket No. 97-00982	May 1997	Chattanooga Gas Company	Tennessee	Gas Depreciation Rates
Cause No. 40395 (II)	June 1997	Wabash Valley Power Association, Inc.	Indiana	Electric Depreciation Rates
Case No. U-11509	Sept 1997	Consumers Energy Company	Michigan	Gas Depreciation Rates and Accounting
Docket No. ER98-11	Sept 1997	Long Island Lighting Company	FERC	Electric Depreciation Rates
Docket No. 8390-U	Dec 1997	Atlanta Gas Light Company	Georgia	Gas Depreciation Rates and Accounting
Cause No. 41118	Mar 1998	Wabash Valley Power Association, Inc.	Indiana	Electric Depreciation Rates
Case No. U-11722	Oct 1998	Detroit Edison Company	Michigan	Electric Depreciation Rates
Docket No. 98-2035-03	Nov 1998	PacifiCorp	Utah	Electric Depreciation Rates
Docket No. 99-4006	April 1999	Nevada Power Company	Nevada	Electric Depreciation Rates
GUD Docket No. 9030	March 2000	Atmos Energy Corporation	Texas	Gas Depreciation Rates and Accounting
GUD Docket No. 9145	April 2000	TXU Gas Distribution	Texas	Gas Depreciation Rates
City of Tyler	Dec 2000	Reliant Energy Entex	Texas	Gas Depreciation Rates and Accounting
Docket No. U-24993	March 2001	Entergy Gulf States Inc.	Louisiana	Electric Depreciation Rates and Accounting
Docket Nos. GR01050328/GR01050297	May 2001	Public Service Electric & Gas	New Jersey	Gas Depreciation Rates and Accounting
Case No. U-12999	July 2001	Consumers Energy Company	Michigan	Gas Depreciation Rates and Accounting
Docket No. 01-10002	Oct 2001	Nevada Power Company	Nevada	Electric Depreciation Rates
Docket No. 14618-U	Nov 2001	Savannah Electric and Power Company	Georgia	Electric Depreciation Rates
Docket No. 01-11031	Dec 2001	Sierra Pacific Power Company	Nevada	Electric Depreciation Rates
Docket No. 010949-EL	Jan 2002	Gulf Power Company	Florida	Electric Depreciation Rates
Docket No. 14311-U	Jan 2002	Atlanta Gas Light Company	Georgia	Gas Depreciation Rates and Accounting
Docket No. UD-00-2	March 2002	Entergy New Orleans, Inc.	New Orleans	Electric Depreciation Accounting

Case No._________
Exhibit No. 4
Witness: Donald S. Roff

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

PACIFICORP

Exhibit Accompanying Direct Testimony of Donald S. Roff

Book Depreciation Study of Electric Property as of March 31, 2002

October, 2002

THIS EXHIBIT IS VOLUMINOUS AND HAS BEEN PROVIDED AS A SEPARATE VOLUME

Case No._________
Exhibit No. 5
Witness: Donald S. Roff

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

PACIFICORP

Exhibit Accompanying Direct Testimony of Donald S. Roff

Annual Accrual Rate Determination

October, 2002

PacifiCorp
Exhibit No. 5
Case No. _____
Witness: Donald S. Roff

PACIFICORP
ANNUAL ACCRUAL RATE DETERMINATION
ACCOUNT 312, BOILER PLANT EQUIPMENT
HUNTER (300305)
IRP DATES
WITH INTERIM ADDITIONS

Interim Net Salvage =	-10.00%
Terminal Net Salvage	-4.88%
Average Future Net Salvage =	-5.18%
Average Age Survivors =	19.00
Average Remaining Life (yrs) =	19.80
Average Service Life =	38.80
Book Reserve Ratio =	32.6%
Terminal COR Reserve =	9,651,719
Interim Retirement Ratio =	0.0035
Interim Addition Factor =	4.0
Depreciation Rate =	3.67%

[1] Year	[2] Interim Retirements $	[3] Interim Net Salvage $	[4] Terminal Retirements $	[5] Terminal Net Salvage $	[6] Interim Additions $	[7] Ending Balance $	[8] Average Balance $	[9] Annual Amount $	[10] Ending Reserve $	[11] Remaining Life yrs	[12 Annual Amount $	[13] Rate %	[14] Ending Reserve $
2002						486,169,151			207,432,846				207,432,846
2003	1,701,592	(170,159)			6,806,368	491,273,927	488,721,539	17,916,429	223,477,524	22.50	13,686,775	2.80	219,247,869
2004	1,719,459	(171,946)			6,877,835	496,432,303	493,853,115	18,104,552	239,690,671	21.50	14,011,264	2.84	231,367,729
2005	1,737,513	(173,751)			6,950,052	501,644,843	499,038,573	18,294,649	256,074,056	20.50	14,355,156	2.88	243,811,621
2006	1,755,757	(175,576)			7,023,028	506,912,113	504,278,478	18,486,743	272,629,466	19.50	14,720,479	2.92	256,600,767
2007	1,774,192	(177,419)			7,096,770	512,234,691	509,573,402	18,680,854	289,358,709	18.50	15,109,593	2.97	269,758,748
2008	1,792,821	(179,282)			7,171,286	517,613,155	514,923,923	18,877,003	306,263,608	17.50	15,525,261	3.02	283,311,906
2009	1,811,646	(181,165)			7,246,584	523,048,093	520,330,624	19,075,212	323,346,009	16.50	15,970,750	3.07	297,289,845
2010	1,830,668	(183,067)			7,322,673	528,540,098	525,794,095	19,275,501	340,607,775	15.50	16,449,959	3.13	311,726,069
2011	1,849,890	(184,989)			7,399,561	534,089,769	531,314,933	19,477,894	358,050,790	14.50	16,967,597	3.19	326,658,786
2012	1,869,314	(186,931)			7,477,257	539,697,711	536,893,740	19,682,412	375,676,956	13.50	17,529,415	3.26	342,131,956
2013	1,888,942	(188,894)			7,555,768	545,364,537	542,531,124	19,889,077	393,488,197	12.50	18,142,550	3.34	358,196,670
2014	1,908,776	(190,878)			7,635,104	551,090,865	548,227,701	20,097,913	411,486,456	11.50	18,815,999	3.43	374,913,016
2015	1,928,818	(192,882)			7,715,272	556,877,319	553,984,092	20,308,941	429,673,697	10.50	19,561,331	3.53	392,352,647
2016	1,949,071	(194,907)			7,796,282	562,724,531	559,800,925	20,522,184	448,051,904	9.50	20,393,768	3.64	410,602,437
2017	1,969,536	(196,954)			7,878,143	568,633,139	565,678,835	20,737,667	466,623,082	8.50	21,333,908	3.77	429,769,855
2018	1,990,216	(199,022)			7,960,864	574,603,787	571,618,463	20,955,413	485,389,257	7.50	22,410,587	3.92	449,991,205
2019	2,011,113	(201,111)			8,044,453	580,637,126	577,620,456	21,175,445	504,352,477	6.50	23,665,954	4.10	471,444,935
2020	2,032,230	(203,223)			8,128,920	586,733,816	583,685,471	21,397,787	523,514,811	5.50	25,165,148	4.31	494,374,630
2021	2,053,568	(205,357)			8,214,273	592,894,521	589,814,169	21,622,464	542,878,350	4.50	27,016,735	4.58	519,132,440
2022	2,075,131	(207,513)			8,300,523	599,119,914	596,007,217	21,849,500	562,445,206	3.50	29,422,344	4.94	546,272,140
2023		-			-	599,119,914	599,119,914	21,963,610	584,408,816	2.50	32,825,558	5.48	579,097,699
2024		-			-	599,119,914	599,119,914	21,963,610	606,372,426	1.50	32,825,558	5.48	611,923,257
2025		-	599,119,914	(29,216,123)	-	-	599,119,914	21,963,610	(0)	0.50	32,825,558	5.48	-
Totals	37,650,254	(3,765,025)	599,119,914	(29,216,123)	150,601,017		12,611,050,618						

Case No. __________
Exhibit No. 6
Witness: Donald S. Roff

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

PACIFICORP

Exhibit Accompanying Direct Testimony of Donald S. Roff

Steam Production Plant
Terminal Net Salvage

October, 2002

STEAM PRODUCTION PLANT
Net Salvage Indicated by Engineering Studies of the Removal of Coal and Lignite Units

(1) Utility and Plant	(2) Number of Units	(3) Total Owned Capacity	(4) Average Capacity	(5) Study Date	(6) All Units Current Removal Cost	(7) 2001 (a)	(8) Net Removal Cost at Study Date
		MW	MW		$	$/kW	$
Alabama Power Company							
Barry 1 - 5	5	1,658	332	2001	98,468,000	59	98,468,000
Chickasaw 1 - 3	3	120	40	1993	4,422,294	37	3,491,000
Gasden 1 & 2	2	130	65	2001	6,331,000	49	6,331,000
Green County 1 & 2 (60% owned)	2	337	280	2001	21,225,600	63	21,225,600
Gorgas 6 - 9	4	565	141	2001	20,137,000	36	20,137,000
Gorgas 10	1	673	673	2001	40,446,000	60	40,446,000
Miller 1 - 4	4	1,471	383	2001	100,969,000	69	100,969,000
Appalachian Power Company							
Amos 1 - 3	3	2,033	678	1990	92,989,833	46	67,177,834
Clinch River 1 - 3	3	705	235	1990	24,686,855	35	17,834,309
Glen Lyn 5 & 6	2	335	168	1990	15,797,732	47	11,412,618
Kanawha River 1 & 2	2	400	200	1990	15,465,115	39	11,172,328
Mountaineer 1	1	1,300	1,300	1990	50,696,285	39	36,624,075
Sporn 1 & 3	2	300	150	1990	16,192,611	54	11,697,887
Consumers Power Company							
Campbell 1 - 3	3	1,294	431	1993	35,844,146	28	28,295,700
Cobb 1 - 5	5	436	87	1993	10,309,355	24	8,138,300
Karn 1 & 2	2	515	258	1993	35,100,172	68	27,708,400
Weadock 1 - 8	8	612	77	1993	1,790,453	3	1,413,400
Whiting 1 - 3	3	310	103	1993	8,377,277	27	6,613,100
Edmonton Power Authority							
Genessee 1 & 2	2	758	379	1995	27,846,494	37	23,321,000
Florida Power Corporation							
Crystal River North 4 & 5	2	1,479	740	1992	53,737,027	36	41,184,957
Crystal River South 1 & 2	2	964	482	1992	55,520,993	58	42,552,218
Florida Power & Light Company							
Scherer 4	1	818	818	1998	20,919,582	26	19,144,381
St. Johns 1 & 2 (20% owned)	2	272	679	1998	17,632,913	65	16,136,613
Georgia Power Company							
Arkwright 1 - 4	4	160	40	1997	11,745,810	73	10,436,000
Bowen 1 - 4	4	3,160	790	1997	67,860,303	21	60,293,000
Branch 1 - 4	4	1,468	367	1997	55,770,087	38	49,551,000
Hammond 1 - 4	4	800	200	1997	32,912,129	41	29,242,000
McDonough 1 & 2	2	490	245	1997	17,924,853	37	15,926,000
Mitchell 1 - 3	3	171	57	1997	16,090,274	94	14,296,000
Scherer 1 - 3 (31% owned)	3	751	807	1997	18,511,677	25	16,447,385
Wansley 1 & 2 (53.5% owned)	2	926	865	1997	23,309,721	25	20,710,385
Yates 1 - 7	7	1,250	179	1997	62,056,054	50	55,136,000
Gulf Power Company							

STEAM PRODUCTION PLANT
Net Salvage Indicated by Engineering Studies of the Removal of Coal and Lignite Units

(1) Utility and Plant	(2) Number of Units	(3) Total Owned Capacity	(4) Average Capacity	(5) Study Date	(6) All Units Current Removal Cost	(7) All Units 2001 (a)	(8) Net Removal Cost at Study Date
		MW	MW		$	$/kW	$
Crist 1 - 7	7	1,055	151	2001	56,368,000	53	56,368,000
Daniel 1 & 2 (50% owned)	2	500	500	2001	17,052,500	34	17,052,500
Scherer 3 (25% owned)	1	205	818	2001	5,109,000	25	5,109,000
Scholz 1 & 2	2	80	40	2001	10,126,000	127	10,126,000
Smith 1 & 2	2	305	153	2001	23,676,000	78	23,676,000
Indiana Michigan Power Company							
Breed 1	1	400	400	1993	18,180,084	45	14,351,526
Rockport 1	1	1,300	1,300	1993	27,480,811	21	21,693,606
Tanners Creek 1 - 4	4	995	249	1993	29,900,156	30	23,603,459
Indianapolis Power & Light Company							
Petersburg 1 - 4	4	1,713	428	1993	80,576,212	47	63,607,606
Pritchard 3 - 6	4	276	69	1993	25,018,510	91	19,749,843
Stout 5 - 7	3	630	210	1993	34,061,953	54	26,888,820
Minnesota Power & Light Company							
Boswell 1 & 2	2	138	69	1992	2,590,298	19	1,985,248
Boswell 3	1	350	350	1992	13,859,960	40	10,622,505
Boswell 4 (80% owned)	1	428	535	1992	16,174,617	38	12,396,497
Hibbard 1 & 2	2	50	25	1992	1,295,642	26	993,002
Laskin 1 & 2	2	110	55	1992	6,786,107	62	5,200,986
Mississippi Power Company							
Daniel 1 & 2 (50% owned)	2	500	500	1996	18,532,735	37	15,986,500
Green County 1 & 2 (40% owned)	2	200	250	1996	15,057,115	75	12,988,400
Watson 1 - 5	5	1,012	202	1996	47,076,961	47	40,609,000
Montana Power Company							
Colstrip 1 & 2 (50% owned)	2	333	333	1994	23,259,989	70	18,912,500
Colstrip 3 & 4 (30% owned)	2	431	719	1994	32,615,148	76	26,519,100
Corette 1	1	163	163	1994	19,698,890	121	16,017,000
Ohio Power Company							
Amos 3 (2/3 owned)	1	867	1,300	1993	36,478,328	42	28,796,329
Cardnal 1	1	600	600	1993	8,894,684	15	7,021,546
Gavin 1 - 2	2	2,600	1,300	1993	27,283,223	10	21,537,628
Kammer 1 - 3	3	630	210	1993	36,189,171	57	28,568,066
Mitchell 1 - 2	2	1,600	800	1993	25,686,910	16	20,277,484
Muskingum River 1 - 4	4	840	210	1993	18,012,242	21	14,219,030
Muskingum River 5	1	585	585	1993	12,516,981	21	9,881,020
Sporn 2, 4 & 5	3	750	250	1993	37,338,030	50	29,474,986
Otter Tail Power Company							
Big Stone	1	456	456	1996	5,086,431	11	4,387,600
PECO Energy Company							

STEAM PRODUCTION PLANT
Net Salvage Indicated by Engineering Studies of the Removal of Coal and Lignite Units

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Number	Total			All Units		Net Removal
	of	Owned	Average	Study	Current	2001	Cost at
Utility and Plant	Units	Capacity	Capacity	Date	Removal Cost	(a)	Study Date
		MW	MW		$	$/kW	$
Conemaugh 1 & 2 (20.72% owned)	2	352	850	1997	23,653,560	67	21,015,882
Cromby 1 & 2	2	345	173	1997	27,072,989	78	24,054,000
Edystone 1 & 2	2	581	291	1997	34,851,380	60	30,965,000
Keystone 1 & 2 (20.99% owned)	2	357	850	1997	24,467,822	69	21,739,343
Pennsylvania Power & Light Company							
Brunner Island 1 - 3	3	1,442	481	1994	206,719,659	143	168,082,000
Holtwood 15 - 17	3	102	34	1994	53,639,719	526	43,614,000
Martins Creek 1 & 2	2	300	150	1994	88,387,345	295	71,867,000
Montour 1 & 2	2	1,500	750	1994	164,666,582	110	133,889,000
Sunbury 1 - 4	4	425	106	1994	167,769,554	395	136,412,000
Public Service Co. of Indiana							
Cayuga 1 & 2	2	995	498	1991	35,995,792	36	26,784,250
Edwardsport 6 - 8	3	160	53	1991	11,841,247	74	8,811,000
Gallagher 1 - 4	4	560	140	1991	22,790,974	41	16,958,625
Gibson 1 - 5	5	2,853	571	1991	89,228,011	31	66,394,020
Noblesville 1 & 2	2	90	45	1991	7,342,823	82	5,463,750
Wabash 1 - 5	5	435	87	1991	21,419,339	49	15,938,000
Wabash 6	1	318	318	1991	10,342,780	33	7,696,000
Public Service Electric & Gas Company							
Mercer 1	1	326	326	1998	7,038,255	22	6,441,000
Mercer 2	1	326	326	1998	17,411,512	53	15,934,000
Hudson 1	1	455	455	1998	21,451,324	47	19,631,000
Hudson 2	1	660	660	1998	46,986,168	71	42,999,000
Savannah Electric Company							
Kraft 1 - 4	4	323	81	2000	28,188,010	87	27,367,000
McIntosh 1	1	168	168	2000	12,387,810	74	12,027,000
Southern California Edison Co.							
Four Corners 4 & 5 (48% owned)	2	754	785	1993	18,312,631	24	14,456,160
Mohave 1 & 2 (56% owned)	2	885	790	1995	25,099,170	28	21,020,160
Southern Electric Generating Company							
Gaston 1 - 4	4	1,000	250	1993	51,348,525	51	40,535,000
Tampa Electric Company							
Big Bend 1 - 4	4	1,635	409	1998	56,508,196	35	51,713,004
Gannon 1 - 6	6	1,180	197	1998	41,931,080	36	38,372,878
TransAlta Utilities Corp.							
Keephills 1 & 2	2	754	377	1995	20,911,438	28	17,513,000
Sheerness 1 (50% owned)	1	183	366	1995	10,056,308	55	8,422,000
Sundance 1 - 6	6	1,987	331	1995	36,885,469	19	30,891,000
Wabamun 1 - 4	4	569	142	1995	21,268,460	37	17,812,000

STEAM PRODUCTION PLANT
Net Salvage Indicated by Engineering Studies of the Removal of Coal and Lignite Units

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
					All Units		
Utility and Plant	Number of Units	Total Owned Capacity	Average Capacity	Study Date	Current Removal Cost	2001 (a)	Net Removal Cost at Study Date
		MW	MW		$	$/kW	$
Wisconsin Electric Power Company							
Port Washington 1 - 5	5	400	80	1990	53,846,285	135	38,899,702
Total or Average	257	69,181	269		3,272,889,551	47	2,745,871,051

NOTES:
(a) Inflation from study date at: 3.00%

Average	60.4
Standard Dev.	69.8

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

In the Matter of the Application of PACIFICORP for an Order Authorizing a Change in Depreciation Rates Applicable to Electric Property.	) DOCKET NO. __________)) Direct Testimony of Barry G. Cunningham

PACIFICORP

October, 2002

Q. Please state your name, business address, and position with PacifiCorp (the Company).

A. My name is Barry G. Cunningham. My business address is 201 South Main, Suite 2300, One Utah Center, Salt Lake City, Utah. My position is Senior Vice President of Generation for PacifiCorp.

Q. Please describe your education and business experience.

A. I have a Bachelor of Arts degree in Physical Science. During my career with PacifiCorp, I have served as a Trainer, Trainer Manager, Assistant Operations Superintendent, a Maintenance Superintendent, a Plant Manager and the Director of Technical Support with responsibility for all of PacifiCorp's small plants. I became Assistant Vice President of Generation in 1998, Vice President of Generation in 1999 and Senior Vice President in 2002, with responsibility for all thermal and hydro generation assets.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is threefold. First, I will describe the process used by PacifiCorp engineers to develop estimated life spans for the Company's steam generating stations. I will explain how steam plant life spans were chosen for this purpose of this proceeding, and I will show how these life span estimates provide a framework for estimating the retirement date for each steam plant. In a similar manner I will describe the procedure used to estimate the retirement date for the Company's hydroelectric generating stations. Retirement dates for each steam and hydro plant were provided by PacifiCorp to Mr. Donald Roff of Deloitte & Touche for use in preparing the depreciation study that is the subject of this proceeding. The depreciation study performed by Mr. Roff (Exhibit No. 4), which is based on plant balances at March 31, 2002, will be referred to hereafter as "the D&T study". The retirement dates provided by the Company to Mr. Roff are the same retirement dates contained in Schedule 3 of the D&T study. I will demonstrate that the estimated retirement dates proposed by the Company for both steam and hydro generation plants are reasonable and prudent and are appropriate inputs for Mr. Roff's depreciation analysis.

Second, I will explain why it is reasonable and necessary to include terminal net salvage, or "decommissioning costs", in the calculation of depreciation rates for generating plants.

Third, I will discuss the depreciation of water rights acquired for the operation of steam generating plants and explain why such depreciation is appropriate for ratemaking purposes.

GENERATION PLANT LIFE ESTIMATION

<u>Steam Plant Life Spans</u>

Q. Please explain what you mean by the "life span" of a steam generating plant.

A. For the purpose of determining depreciation, the life span of a steam plant is the period of time that begins when the plant is initially placed in service and begins to generate electricity and ends when the plant is finally removed from service and ceases to generate electricity. In other words it is the period of time during which electric customers benefit from the generation output of the plant.

Q. When a steam plant is removed from service, will it be retired and its investment removed from the Company's accounting records?

A. It may not be immediately retired from an accounting perspective. More likely the plant will be retained in a reserve status for a period of time until plans for its final disposition are made.

Q. If an accounting retirement is not made, will the plant remain in rate base and continue to impose costs on customers?

A. No. Under the life span concept a plant will be fully depreciated by the time it is finally removed from service.

Q. Why is it necessary to estimate the life span of a steam plant?

A. One major component of PacifiCorp's cost of service is the recovery of capital investment in steam generating plants. This recovery is accomplished through depreciation expense over the productive life of each plant. From the standpoint of setting depreciation rates it is necessary to have a reasonable estimate of the life span of a plant as soon as it is placed in service. For depreciation purposes all steam plant life spans are estimates that may be adjusted over time as circumstances warrant.

Q. What is PacifiCorp's current estimated life span for steam generating plants?

A. The Company estimates that, absent extenuating circumstances, the life span of its steam generating units is 40 years. After careful analysis the Company estimates that all of its steam plants have 40 year life spans, except for Gadsby, Dave Johnston, Hayden, Carbon, and Naughton, which are estimated to have life spans of at least 50 years.

Q. Who prepared the life span analysis?

A. The life span analysis was prepared by PacifiCorp's Generation Engineering staff under my direction. This group includes individuals with over twenty years of service with the Company who are experienced in all areas of steam plant operation, including the design, construction, operation and maintenance of the Company's existing units.

Q. What criteria were considered in the life span analysis?

A. The life span analysis focused on four main areas: (1) an examination of the original engineering design life of the plants; (2) an evaluation of the operating and maintenance history of the plants as determined by owner operational requirements; (3) an assessment of the current condition of major equipment components; and (4) an assessment of current and potential future issues that may affect the continued operation of coal-fired generation plants, such as new generation technology and environmental issues.

Q. Please describe the Company's examination of engineering design lives.

A. One of the fundamental assumptions underlying the analysis is that the life span of PacifiCorp generating units should be consistent with their original engineering design lives, absent some event or set of circumstances that would indicate a need to change. To determine the original design life the Company contacted several of the engineer/architects of its existing plants; specifically, Bechtel for Naughton Units 1 and 2, Jim Bridger and Centralia, Raytheon Engineers and Constructors (formerly Stearns-Roger) for Naughton Unit 3, Huntington Units 1 and 2 and Hunter Units 1 and 2, and Brown and Root for Hunter Unit 3. Discussions with these engineers/architects led to the conclusion that the design life of PacifiCorp steam plants constructed from the late 1960's through the early 1980's was 30-35 years. To confirm the reasonableness of the design life estimates, the Company also contacted the suppliers of the majority of our major steam plant equipment—General Electric for steam turbine-generators and ABB for boiler equipment. Discussions with these two equipment vendors suggested that during the period in which our major plants were designed, boiler equipment had an expected life of 30 years while steam turbines were expected to last 40 years. Thus, based on information provided by design engineers and equipment suppliers, the Company concluded that 35-40 years was a reasonable estimate for the original design life of its major steam generating plants.

Q. You indicated that there might be events or circumstances occurring during the life of a steam generating plant that could affect its original design life. What kind of events or circumstances were you referring to?

A. In preparing its life span analysis the Company considered three types of extraordinary events, the occurrence of any one of which might require a departure from original plant design life. One such event would be plant operating experience or maintenance practices that departed significantly from the original manufacturer's operating procedures or design parameters. The second type of event would be the installation of equipment or the imposition of operating restrictions necessitated by environmental regulations not anticipated at the time of original plant design. The third type of event would be the infusion of life-extending capital that might lengthen the lives of major equipment items, compensate for aggressive operating and maintenance practices or respond to the requirements of environmental regulation.

Q. Did the Company evaluate the operating and maintenance history of its steam plants to determine compliance with original design parameters?

A. Yes. A review of historical records indicates that PacifiCorp's steam plants have been operated and maintained in a manner consistent with the 35-40 year life expectation reflected in original design parameters. Manufacturer's guidelines and/or operating recommendations from design engineers have been translated into training materials and operating procedures used throughout the Company's thermal fleet. A review of preventative maintenance logs, work order and equipment histories, and overhaul histories indicates that required maintenance procedures have been consistently applied for all plants. This is further demonstrated by the high capacity factors and low forced outage rates exhibited by PacifiCorp's thermal fleet.

Q. Has the Company identified significant environmental issues, not anticipated at the time of plant design, that could affect the 35-40 year original design life expectation?

A. The following environmental issues are creating risk that the Company's newer coal-fired generating plants may not reach their original design life estimate:

1. The Environmental Protection Agency (EPA) continues to emphasize the need for continued reductions in sulfur dioxide (SO_2) and oxides of nitrogen (NO_x) emissions. Vehicles for achieving these reductions include the work of the Grand Canyon Transport Commission, new visibility initiatives,

enforcement of New Source Review (NSR) regulations, and proposed new legislation aimed at substantial reductions in SO2 and NOx. Major legislative proposals include Senate Bill S556, sponsored by Senator Jeffords and President Bush's Clean Skies Initiative (CSI).

2. Success of OTAG (Ozone Transport Assessment Group) implementation in the eastern United States will hasten the implementation of new requirements for NOx reductions to the 0.2 to 0.10 lb/mmBtu level. Reductions to this level on our coal-fired boilers will require the addition of Selective Catalytic Reduction (SCR) equipment.
3. There are continued efforts by many groups to commit the U.S. to reduce carbon dioxide (CO2) emissions. Current schedules under the Kyoto Agreement call for reductions in CO2 emissions beginning in 2008.
4. The Maximum Achievable Control Technology (MACT) rule under the Clean Air Act (CAA) has identified a need to reduce mercury emissions by 2008. Rulemaking on emission reduction requirements will be proposed by the end of 2003 and finalized by the end of 2004.
5. There is continued vocal opposition to coal-fired generation from environmental groups, with an increasing likelihood of citizen suits to restrict the status-quo level of coal-based generation, similar to the Company's experience at its Hayden and Craig plants.

While it is impossible to quantify the potential effect of each of these initiatives on individual Company plants at this time, the range and magnitude of future environmental issues raises serious questions about the long term viability of coal-fired generation. From the standpoint of life span analysis PacifiCorp believes it is likely that future environmental costs will substantially affect the economics for plants whose design life would expire in the 2010-2025 time frame.

Q. Has the expenditure of life-extending capital had an effect on the life span estimates for any of the Company's generating plants?

A. Yes. The infusion of life-extending capital has extended the estimated life span to at least 50 years for Gadsby, Hayden and Dave Johnston. Gadsby was refurbished in connection with its conversion to gas firing capabilities in the early 1990's. The Company anticipates that the addition of a scrubber at Hayden will allow the plant to comply with environmental regulations and achieve a 50-year life span, although there remains some risk that additional environmental regulations could limit this life. At Dave Johnston, the installation of new coal unloading facilities will allow the plant to burn purchased coal and continue to operate beyond the closure of the adjacent Glenrock Coal Mine.

Q. Based on its evaluation of the criteria you have just described, how did the Company arrive at a life span of 40 years for plants that have not had life-extending capital additions?

A. As I explained previously, PacifiCorp believes that, absent extenuating circumstances, steam plant life span should be consistent with original design life. Design life was determined to be 35-40 years. An examination of plant operating and maintenance histories and an evaluation of environmental issues indicates that there is no compelling reason to depart from the design life at this time.

Therefore, a 40-year life span is a conservative reflection of the original design life estimate.

Q. Why is a 40-year life span more "conservative" than a 35-year life span?

A. The life span analysis was prepared to provide inputs to the depreciation study. All else being equal, longer plant lives mean lower depreciation rates. Therefore, a 40-year life span is more conservative than 35 years because it results in more conservative (lower) depreciation rates.

<u>Recommended Steam Plant Life Spans for Depreciation Study</u>

Q. You have just explained that 40 years would be an appropriate life span for the Company's steam generating plants, with the exception of certain plants that have had life-extending capital additions. Has the Company reflected these life span estimates in the current depreciation study?

A. No. For purposes of the current depreciation study PacifiCorp has elected to continue using the steam plant life spans reflected in current depreciation rates. Current depreciation rates for the Gadsby, Dave Johnston, Hayden and Carbon Plants are based on life spans of 54 years, Blundell of 37 years and James River of 20 years, and all other PacifiCorp steam plants on life spans of 44 years. The only change the Company has made to these life spans is to further extend the life span for the Naughton Plant from 44 years to 54 years, to reflect the most recent engineering analysis.

Q. Why did PacifiCorp choose to use steam plant life spans that are longer than those supported by its own engineers?

A. While PacifiCorp believes that a strong case can be made for the use of a 40-year life span, the Company hopes to expedite the regulatory approval process by proposing no significant changes in current steam plant life spans. The Company believes that current life spans, adjusted only to extend the life at Naughton, provide a reasonable and conservative basis for calculating steam plant depreciation in the current study. When PacifiCorp files its next depreciation study, typically in five years, it may be appropriate to revisit this issue.

Steam Plant Retirement Dates

Q. How was the estimated life span for each plant converted into an estimated retirement date?

A. The estimated life span was added to the original in-service date for each generating unit to arrive at its estimated retirement date. For example, if a unit had an in-service date of 1980 and a 44-year estimated life span, its estimated retirement date would be 2024. For multiple-unit plants, the age was calculated for each unit. Then a weighted-average age for the entire plant was determined by weighting the capacity of each unit. An average retirement date was then calculated based on the remaining life.

Q. Were the estimated retirement dates calculated by the Company for each steam plant based on current life spans provided to Mr. Roff for use in preparing the depreciation study?

A. Yes. The estimated plant retirement dates were provided to Mr. Roff in the form of the document contained in Exhibit No. 7.

Hydroelectric Plant Retirement Dates

Q. Is the process used to estimate retirement dates for PacifiCorp's hydro generation plants similar to the process used for steam plants?

A. Conceptually the process is very similar. The primary difference is that it is not possible to use generic life span estimates for hydro plants. While steam plants of similar size, vintage, and design requirements would be expected to have the same life span, each hydro plant is unique. Therefore, it is necessary to estimate the life span of each hydro plant separately; or in effect, to determine the retirement date for each hydro plant on an individual basis.

Q. What criteria are important in estimating the retirement date of a hydro plant?

A. The remaining useful lives of hydro facilities are governed either by the terms of operating licenses or by the remaining life of critical civil/structural or electro-mechanical components.

Q. Who prepared the estimated retirement dates for hydro plants?

A. The hydro plant retirement dates were estimated by PacifiCorp's Hydro Engineering and Planning staff. These individuals have experience in both plant operation and maintenance and in project relicensing.

Q. What license are you referring to?

A. The majority of PacifiCorp's hydro projects are federally licensed under the jurisdiction of the Federal Energy Regulatory Commission (FERC) which acts under the authority of the Federal Power Act (FPA). Hydro projects receive their initial license when they are first placed in service and may be relicensed upon expiration of the initial term. This initial term is usually for 50 years. FERC may grant new licenses of up to 50 years, depending upon the unique circumstances at each project. Currently, the most common relicensing period is 30 years. Over 90percent of the Company's hydro capacity is or will be in the relicensing process in the next few years.

Q. How were the decision criteria applied to determine the retirement date for each hydro plant?

A. As previously mentioned, most of the Company's hydro capacity has been recently relicensed, is currently undergoing relicensing or soon will be. For plants currently in the relicensing process and plants that will begin relicensing in the near future, the estimated retirement date is the date of expiration of the current license plus 30 years (the most common period for new FERC licenses). For example, if a plant's current license expires in 2000, the estimated retirement date for that facility is 2030. For plants that have been recently relicensed, the estimated retirement date is the expiration date of the new license. The remaining life span of the plant is the same as the life of the license.

Q. Is there any exception to the practice of basing estimated retirement dates on FERC license expirations?

A. Yes. As I indicated before, the other primary driver of expected hydro plant life is the remaining life of critical components. PacifiCorp has a number of smaller hydro projects where significant new investment could make the plants uneconomical to operate given current alternative options to supply this energy. If an aging critical component were to fail at such a plant, it is likely that an economic analysis would indicate that the Company should retire the facility rather than spend the capital necessary to operate the plant for the remainder of its license term. For plants where Company engineers have determined that the expected remaining life of a critical component is shorter than the FERC license period, the retirement date of that plant has been estimated to reflect only the remaining useful life of the component. For example, consider a hydro plant with a FERC license expiration of 2025 that will require a complete flowline replacement in 2015. Company engineers believe that replacement of the flowline cannot be economically justified. The estimated retirement date for that plant will be based on the expected critical component failure date of 2015 rather than the 2025 license expiration date.

Q. If the continued operation of a hydro plant is not constrained by critical component failures, why should its life span be limited to the expiration of a FERC license? Wouldn't it be reasonable to expect FERC licenses to continue to be renewed indefinitely?

A. It would be imprudent to anticipate approval of license renewals beyond the near term. The FERC is responsible for hydroelectric project licensing under the Federal Power Act . Historically, FERC has balanced the need for power produced by projects with the need to protect the surrounding environment and natural resources. However, FERC no longer has the discretion to balance hydro interests with other resource issues given the U.S. Supreme Court's rulings on Section 401 of the Clean Water Act (CWA), endangered species listings under the Endangered Species Act (ESA) and other rulings under the FPA. For example, the U.S. Fish and Wildlife Service and the National Marine Fisheries Service have prescriptive authority under the FPA to provide fish passage in any manner they deem reasonable. As a result, typical license conditions now routinely include revised operating requirements and construction of new environmental mitigation facilities that may make the project(s) uneconomical to continue to operate in the future. This economic viability will need to be determined for each project, but such determination cannot be conclusively made until a new license is re-issued by FERC. For this reason PacifiCorp cannot reliably forecast operating lives beyond current license expiration dates. The estimated hydro plant retirement dates developed by Company engineers using the criteria that I have just described are reasonable and prudent in this dynamic, changing arena and are the appropriate inputs for Mr. Roff's depreciation analysis.

Q. **How were the estimated hydro plant retirement dates developed by the Company provided to Mr. Roff?**

A. The estimated hydro plant retirement dates were provided to Mr. Roff in the form of Exhibit No. 8.

OTHER PRODUCTION PLANT

Q. **What process was used by PacifiCorp to estimate retirement dates for its Other Production Plants?**

A. The process was similar to that used for the hydro generation facilities. The life spans for Other Production were assumed to be the length of either the Power Purchase Agreement for the specific facility or the expected life of a critical component. Little Mountain and Foote Creek (aka Wyoming Wind) use the contract length as the estimated life span for their respective facilities. The estimated life spans for the Gadsby Units 4, 5 and 6 were based on the 25-year design life span of the combustion turbine.

Q. Why is the contract life a good estimate of plant life?

A. Given the uncertainty in the power market, it is difficult to project the economic value of the plant past the end of the contract life. The future economic viability for each project will need to be evaluated as it nears the end of its estimated life span.

Q. Why is there a different life span for the Hermiston gas-fired plant than the Gadsby gas-fired plant?

A. The Hermiston gas-fired plant is a combined cycle base-loaded facility, which is designed to run at a steady state condition. Gadsby Units 4, 5 and 6 are peakers, and are therefore expected to cycle on and off at a higher rate. The cycling of the plant takes life out of the combustion turbines and reduces their life span.

Q. How were the estimated other production plant retirement dates developed by the Company provided to Mr. Roff?

A. The estimated other production plant retirement dates are included in Exhibit No. 7.

TERMINAL NET SALVAGE (DECOMMISSIONING COST)

Q. Please explain the term "terminal net salvage" or "decommissioning cost"?

A. As I use the term, terminal net salvage refers to the cost of removing facilities that have been retired and restoring the site to its original grade. It does not contemplate site re-vegetation or other landscaping activities.

Q. Do the depreciation rates being proposed by the Company in this proceeding include recovery of terminal net salvage for generation plants?

A. The depreciation rates for steam generating plants include recovery of terminal net salvage. With the exception of the Condit and American Fork Plants, which the Company expects to remove, the depreciation rates for hydro plants do not provide for recovery of terminal net salvage.

Q. Why should there be a difference in the recovery of terminal net salvage between steam and hydro plants?

A. Conceptually there should be no difference—terminal net salvage should be reflected in depreciation rates. The cost of removing coal-fired plants is generally consistent for plants of similar size and vintage. This consistency facilitates preparation of reasonable terminal net salvage estimates for steam plants. However, every hydro plant is uniquely situated and the estimated removal costs would have to be individually determined. PacifiCorp will continue to evaluate the most appropriate way to reflect hydro terminal net salvage in future depreciation studies, but it was decided not to include these costs in the current study.

Q. How were the terminal net salvage factors for steam production plant determined?

A. The terminal net salvage for PacifiCorp's steam generating plants was estimated by Mr. Roff. A description of the procedures used is presented in his direct testimony filed in this proceeding on page 11.

Q. Based on the Company's actual experience, does Mr. Roff's estimate of terminal net salvage for steam plants appear to be reasonable for PacifiCorp?

A. Yes, in fact it appears to be rather conservative. Mr. Roff estimates approximately 8 percent negative net salvage (8 percent) for steam plant decommissioning. (Net salvage is negative when cost of removal exceeds salvage value. The net salvage percentage is calculated by dividing the net salvage amount by the retirement amount.) PacifiCorp has retired two steam generating plants in the last fifteen years—the Hale Plant and the Jordan Plant—both of which have been removed. The Company's actual terminal negative net salvage for the Hale Plant was (14%) and for the Jordan Plant it was (190%).

Q. Does PacifiCorp expect to remove steam generating plants that are retired in the future?

A. Yes. It has been the Company's practice to remove thermal plants upon retirement for a variety of reasons, and it is its current intention to continue to do so. PacifiCorp assumes that even if laws and regulations do not currently exist which require removal of generation plants upon retirement, laws and regulations may be enacted that would require removal if the owner or operator fails to do so. There are public safety and environmental issues associated with generation plants, and the public may demand their removal if the owner or operator does not do so. The Company does not believe it is reasonable to assume that retired generation plants will be allowed to remain in place indefinitely in the future. In addition, it is unlikely that PacifiCorp could dispose of the sites of retired generation plants without removal. In fact, even if the Company were to retain the site for its own use, it would probably be necessary to remove the old plant before a new plant could utilize transmission or other site advantages. The Company believes that consideration of the potential obligations associated with indefinitely holding a retired generation plant might indicate that removal is the most prudent course and may be in the long-term public interest.

Q. Does recovery of terminal net salvage costs through steam plant depreciation expense represent sound ratemaking policy?

A. Yes, it does. Two of the most basic precepts of ratemaking policy are that customers should pay for their cost of service and that costs should be matched with benefits. Consistent with these principles, customers who benefit from the output of a steam generating plant should bear all the costs of producing that output, including the cost of constructing the plant and subsequent capital additions, the costs of operating and maintaining the plant over its productive life, and ultimately the cost of retiring and removing the plant. Recovery of terminal net salvage through depreciation expense over the useful life of the plant is the only way to achieve a full and fair matching of costs and benefits. If recovery of terminal net salvage were to be deferred until the plant is actually retired, some customers would inevitably pay less than their cost of service while other customers would pay more than their fair share.

Q. Is the estimated removal cost for the Condit and American Fork hydro plants included in the current depreciation study prepared by Mr. Roff?

A. Yes. The depreciation rates developed by Mr. Roff for the Condit Plant reflect the recovery of $19.7 million for removal of the Condit dam and $1 million for removal of the American Fork facilities. This recovery is explained in Mr. Roff's direct testimony on page 12 and is documented in the depreciation study, Exhibit No. 4, Schedule 3.

Q. Are Condit dam removal costs reflected in current depreciation rates?

A. Yes. Current depreciation rates include recovery of Condit removal costs.

Q. Please describe the situation involving the American Fork Plant.

A. The cost of removing the American Fork Plant has not been addressed in previous depreciation studies. However, the current FERC license for operating the plant expires in 2008, and PacifiCorp is faced with two alternatives—relicense the project and continue to operate it or decommission the facility. Since economic analysis has demonstrated that a relicensed American Fork project would not be cost effective, the Company does not plan to continue to operate the plant after the current license expires in 2008. The Company's current estimate of the cost that will be required to decommission the American Fork Plant is $1 million. This amount is included in the current depreciation study as removal cost in order to recover it over the remaining useful life of the plant from the customers who will be served by the plant.

DEPRECIATION OF WATER RIGHTS

Q. Please describe the water rights that are at issue in this proceeding?

A. Coal-fired generating plants require significant amounts of water for operating and cooling purposes. The water rights at issue, most of which are associated with the

Hunter, Huntington, and Dave Johnston Plants, were acquired to satisfy this operational need for water. For the most part the cost of obtaining these rights was included in the original plant construction cost, although some additional rights have been acquired over the years to meet changing needs.

Q. Why is it appropriate to depreciate the cost of water rights?

A. All generating plant construction costs, including water rights, should be recovered from those customers who benefit from the output of the unit over its productive life. It is necessary, then, to allocate the cost of water rights to generation expense in a systematic and rational fashion over the life of the plant. This allocation is accomplished through depreciation.

Q. For the most part, PacifiCorp's coal-fired generating plants are located in arid areas where water is a scarce commodity. Why wouldn't the value of water rights be expected to actually appreciate over the life of the plant—thereby eliminating any need for cost allocation through depreciation?

A. Although the value of water rights might be expected to increase over time, this expectation is based on the water being used for the same purpose at the time of acquisition and sale. The fact is that the Company was required to pay a significant premium above the market value of water for agricultural purposes to acquire the large blocks of water necessary to operate a generating plant. To operate the Hunter and Huntington plants, PacifiCorp had to acquire one-third of the water rights in Emery County, Utah. The water will be sold for agricultural purposes. Upon plant retirement, PacifiCorp will be unable to recover the premium it paid at acquisition by selling large blocks of water whose only use is growing hay and raising cattle.

Q. What makes you think that the water rights currently owned by PacifiCorp will not be needed in the future for non-agricultural purposes in Emery County?

A. These water rights will not be available until the Hunter and Huntington Plants are retired and closed. In 1998, between the generating plants and their associated coal mines, PacifiCorp directly employed more than 20 percent of the employed labor force in Emery County and made possible many additional jobs in supporting industries. The Company also paid more than 70 percent of total Emery County property taxes in 1998. Closure of the Company facilities will be a major economic blow to the area and may provide the impetus for an outward migration of job-seekers. Under these circumstances the municipalities in Emery County will likely need less water rather than more, and there are few prospects for other major industrial development in this area. Thus, the major use for the water rights owned by the Company will undoubtedly be agricultural.

Q. Is there a similar situation with the water rights acquired for the Dave Johnston Plant in Wyoming?

A. Yes. PacifiCorp needed to acquire very high quality water rights to ensure the continued, uninterrupted operation of the Dave Johnston Plant because there is no water storage capability in the area. The rights acquired were converted from agricultural use at a substantial premium. Because the value of water for generation is so much greater than the value of water for ranching, it is unrealistic to expect the conversion premium to be regained when the water is again made available for agricultural use.

Q. How do the facts you have just described support the depreciation of water rights?

A. Since the future value of water rights is expected to be small compared to their acquisition cost, it is sound ratemaking policy to recover the cost of these rights through depreciation expense from the customers who benefit from their use. It makes no sense to require a future generation of customers to bear the risk of paying for water rights for a plant that never served them.

Q. You have explained that when the steam plants are retired, the residual value of water rights will be small compared to their acquisition costs. How has this residual value been reflected in the depreciation study?

A. In arid states such as Utah and Wyoming, water rights will always have value. For purposes of the depreciation study, the Company has included a ten percent salvage value for the water rights when they are converted from industrial to agricultural use upon the retirement of the generating plants. Such inclusion reduces depreciation expense for these plants.

CONCLUSION

Q. Based on the foregoing testimony, what conclusions have you reached?

A. It is my opinion that the life spans reflected in current depreciation rates for PacifiCorp's steam generating plants (adjusted only to extend the life of the Naughton Plant) provide a reasonable basis in this case for the estimated retirement dates used as inputs for Mr. Roff's depreciation analysis. Similarly, it is my opinion that the hydro plant retirement dates provided to Mr. Roff are reasonable and are based on the latest engineering estimates. I conclude that the terminal net salvage calculated by Mr. Roff for PacifiCorp steam generating plants is reasonable and conservative, based on the Company's actual experience. It is necessary to include steam plant terminal net salvage in depreciation rates to properly match customer benefits with customer costs and to ensure that all customers pay their full and fair cost of service. These same principles of ratepayer equity require that the Condit and American Fork hydro plant decommissioning costs be recovered through depreciation expense from the customers being served by the these hydro plants. Finally, I conclude that the cost of water rights acquired to operate steam generating plants should be recovered through depreciation from the generation of customers who were served by those plants.

Q. Does this conclude your testimony?

A. Yes.

Case No. _________
Exhibit No. 7
Witness: Barry G. Cunningham

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

PACIFICORP

Exhibit Accompanying Direct Testimony of Barry G. Cunningham

Steam Plant Retirement Dates

October, 2002

Power Supply Estimated Plant Lives

Plant	PacifiCorp Share Net Rating (MW)	Commercial Date	Current Age of Unit	Weighted Average Age of Plant	Power Supply Recommended Life	Power Supply Recommedation Year Ending Life	Years Remaining from 2002
Blundell	23	1984	18	18.0	37.0	2021	19
Carbon-1	70	1954	48				
Carbon-2	105	1957	45	46.2	54.0	2010	8
Cholla-4	380	1981	21	21.0	44.0	2025	23
Colstrip-3	72	1984	18				
Colstrip-4	72	1986	16	17.0	44.0	2029	27
Craig-1	83	1980	22				
Craig-2	83	1979	23	22.5	44.0	2024	22
Dave Johnston-1	106	1959	43				
Dave Johnston-2	106	1960	42				
Dave Johnston-3	230	1964	38				
Dave Johnston-4	330	1972	30	35.8	54.0	2020	18
Foote Creek	33	1999	3	3.0	25.0	2024	22
Gadsby-1	60	1951	51				
Gadsby-2	75	1952	50				
Gadsby-3	100	1955	47	49.0	54.0	2007	5
Gadsby-4	40	2002	0				
Gadsby-5	40	2002	0				
Gadsby-6	40	2002	0	0.0	25.0	2027	25
Hayden-1	45	1965	37				
Hayden-2	33	1976	26	32.3	54.0	2024	22
Hermiston 1	119	1996	6	6.0			
Hermiston 2	119	1996	6	6.0	35.0	2031	29
Hunter-1	389	1978	24				
Hunter-2	259	1980	22				
Hunter-3	460	1983	19	21.5	44.0	2025	23
Huntington-1	440	1977	25				
Huntington-2	455	1974	28	26.5	44.0	2019	17
James River	52	1996	6	6.0	20.0	2016	14
Jim Bridger-1	353	1974	28				
Jim Bridger-2	353	1975	27				
Jim Bridger-3	353	1976	26				
Jim Bridger-4	347	1979	23	26.0	44.0	2020	18
Little Mountain	14	1971	31	31.0	35.0	2006	4
Naughton-1	160	1963	39				
Naughton-2	210	1968	34				
Naughton-3	330	1971	31	33.7	54.0	2022	20
Wyodak-1	268	1978	24	24.0	44.0	2022	20

Case No.__________
Exhibit No. 8
Witness: Barry G. Cunningham

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

PACIFICORP

Exhibit Accompanying Direct Testimony of Barry G. Cunningham

Hydro Plant Retirement Dates

October, 2002

Power Supply Estimated Plant Lives

Plant	PacifiCorp Share Net Rating (MW)	Location	Commercial Date	Current Age of Unit	Weighted Average Age of Plant	Power Supply Recommended Life	License Expiration Date	Power Supply Recommedation Year Ending Life	Years Remaining from 2002
Ashton	6.85	Idaho	1923	79	79	105	2028	2028	26
Bend	1.11	Oregon	1913	89	89	92	Unlicensed	2005	3
Big Fork	4.15	Montana	1924	78	78	107	2001	2031	29
Clearwater-1	15.00	Oregon	1953	49	49	87	1997	2040	38
Clearwater-2	26.00	Oregon	1953	49	49	87	1997	2040	38
Cline Falls	1.00	Oregon	1943	59	59	62	Unlicensed	2005	3
Condit	9.60	Washington	1913	89	89	91	1993	2006	4
Copco-1	20.00	Oregon	1918	84	84	118	2006	2036	34
Copco-2	27.00	Oregon	1925	77	77	100	2006	2025	23
Cove	7.50	Idaho	1917	85	85	114	2001	2031	29
Cutler	30.00	Utah	1927	75	75	97	2024	2024	22
Eagle Point	2.80	Oregon	1957	45	45	53	Unlicensed	2010	8
East Side	3.20	Oregon	1924	78	78	82	2006	2010	8
Fall Creek	2.20	Oregon	1908	94	94	98	2006	2036	34
Fish Creek	11.00	Oregon	1952	50	50	88	1997	2040	38
Fountain Green	0.16	Utah	1922	80	80	88	Exempt	2010	8
Grace	33.00	Idaho	1923	79	79	108	2001	2031	29
Granite	2.00	Utah	1896	106	106	134	Unlicensed	2030	28
Gunlock	0.75	Utah	1917	85	85	103	Exempt	2020	18
Iron Gate	18.00	Oregon	1962	40	40	74	2006	2036	34
JC Boyle	80.00	Oregon	1958	44	44	78	2006	2036	34
Last Chance	1.70	Idaho	1984	18	18	41	Exempt	2025	23
Lemolo-1	29.00	Oregon	1955	47	47	85	1997	2040	38
Lemolo-2	33.00	Oregon	1956	46	46	84	1997	2040	38
Merwin	136.00	Washington	1932	70	70	104	2009	2036	34
Naches	6.37	Washington	1909	93	93	97	Unlicensed	2006	4
Naches Drop	1.40	Washington	1915	87	87	91	Unlicensed	2006	4
Onieda	30.00	Idaho	1915	87	87	116	2001	2031	29
Paris	0.70	Idaho	1910	92	92	105	Exempt	2015	13
Pioneer	5.00	Utah	1914	88	88	116	2000	2030	28
Powerdale	6.00	Oregon	1923	79	79	95	2000	2018	16
Prospect-1, 2 & 4	36.76	Oregon	1912	90	90	123	2005	2035	33
Prospect-3	7.20	Oregon	1932	70	70	87	2019	2019	17
Sand Cove	0.80	Utah	1920	82	82	100	Exempt	2020	18
Skookumchuck	1.00	Washington	1990	12	12	58	Exempt	2048	46
Slide Creek	18.00	Oregon	1951	51	51	89	1997	2040	38
Snake Creek	1.18	Utah	1910	92	92	110	Unlicensed	2020	18
Soda	14.00	Idaho	1924	78	78	107	2001	2031	29
Soda Springs	11.00	Oregon	1952	50	50	88	1997	2040	38

Power Supply Estimated Plant Lives

Plant	PacifiCorp Share Net Rating (MW)	Location	Commercial Date	Current Age of Unit	Weighted Average Age of Plant	Power Supply Recommended Life	License Expiration Date	Power Supply Recommedation Year Ending Life	Years Remaining from 2002
St. Anthony	0.50	Idaho	1915	87	87	113	2028	2028	26
Stairs	1.00	Utah	1914	88	88	111	2000	2025	23
Swift-1	240.00	Washington	1958	44	44	78	2006	2036	34
Tokatee	42.50	Oregon	1939	63	63	101	1997	2040	38
Upper American Fork	0.95	Utah	1964	38	38	66	2000	2008	6
Upper Beaver	2.52	Utah	1907	95	95	123	Exempt	2030	28
Veyo	0.50	Utah	1920	82	82	100	Exempt	2020	18
Viva Naughton	0.74	Wyoming	1986	16	16	54	Exempt	2040	38
Wallowa Falls	1.10	Oregon	1921	81	81	95	2016	2016	14
Weber	3.85	Utah	1949	53	53	71	2020	2020	18
West Side	0.60	Oregon	1908	94	94	98	2006	2010	8
Yale	134.00	Washington	1963	39	39	73	2001	2036	34
	1,068.69								
The following are associated with and support PacifiCorp's Hydro facilities, but do not have generation									
Keno Regulating Dam								2036	34
Klamath Lake Reservoir								2036	34
Lifton								2048	46
North Umpqua General								2040	38
The following is operated by PacifiCorp, but is owned by others									
Olmsted	10.30							2016	14